BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	Docket No. 05-0315
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules.	)	
	)	

HELCO

REBUTTAL TESTIMONIES
AND EXHIBITS

BOOK 2 OF 2

March 27, 2007

REBUTTAL TESTIMONY OF
JOSE S. DIZON

MANAGER
ENGINEERING DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Plant Additions
Plant Retirements
Joint Pole Sales
Property Held For Future Use
Contributions in Aid of Construction
Customer Advances

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jose S. Dizon and my business address is 54 Halekauila Street, Hilo, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Engineering Department at Hawaii Electric Light Company, Inc. ("HELCO"). My experience and educational background are listed in HELCO-R-4A00.

Q. Have you previously submitted testimony in this proceeding?

A. No. The written direct testimony, exhibits, and supporting workpapers as HELCO T-14 were submitted by Clyde Nagata, the previous Manager of the Engineering Department at HELCO prior to his retirement. I am adopting the HELCO T-14 testimony, exhibits, workpapers, and responses to information requests.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will present the Company's rebuttal position with respect to plant additions, plant retirements, joint pole sales, property held for future use ("PHFFU"), contributions in aid of construction ("CIAC"), and customer advances. As discussed further below, HELCO and the Consumer Advocate have reached an agreement on all of the areas covered in my testimony.

Q. How is your rebuttal testimony organized?

A. In this rebuttal testimony, I will:

1) Summarize the Company's rebuttal position, including the changes made by the Company in preparing its rebuttal position; and

2) Summarize the areas of agreement between the Company and the Consumer Advocate.

HELCO'S REBUTTAL POSITION

Q. What revisions have you made to the 2006 test year estimates presented in the direct testimony?

A. My rebuttal testimony presents revised amounts to reflect actuals as of 12/31/06 for the following areas:

1) plant additions (refer to HELCO-RWP-1401 and CA-SIR 51)
2) plant retirements (refer to HELCO-R-1202)
3) joint pole sales (refer to HELCO-RWP-1401)
4) CIAC (refer to HELCO-R-1603)
5) customer advances (refer to HELCO-R-1604)

As discussed further below, HELCO and the Consumer Advocate are in agreement on the plant additions, plant retirements, joint pole sales, CIAC and Customer Advances amounts.

Q. Did your rebuttal testimony present any other revisions to the 2006 test year estimates presented in direct testimony?

A. Yes. HELCO revised the 2006 test year PHFFU to reflect that the Palani Substation project was not placed in service during the 2006 test year. As discussed further below, HELCO and the Consumer Advocate are in agreement on the test year PHFFU.

AREAS OF AGREEMENT

Plant Additions

Q. What are HELCO's 2006 plant additions?

A. HELCO's 2006 plant additions are $47,729,087. This is the total recorded plant additions for the 2006 test year as of 12/31/06. CA-SIR 51 contains a listing of all the projects and their cost that were closed to plant, as well as a listing of all the projects that were not completed in the 2006 test year.

Q. How does this compare with the Consumer Advocate's estimate for plant additions?

A. The Consumer Advocate concurs with HELCO's $47,729,087 as noted in CA T-3 WP B-1.1 and Exhibit CA-101, Schedule B-1.

<u>Plant Retirements</u>

Q. What are HELCO's revised 2006 test year plant retirements?

A. HELCO's recorded 2006 test year plant retirements as of 12/31/06 are $4,654,045 as shown on HELCO-R-1401, HELCO-RWP-1401 and HELCO-1202, which is from the accounting records.

Q. How does this compare with the Consumer Advocate's estimate for plant retirements?

A. The Consumer Advocate did not object or take issue with the $3,804,000 plant retirement estimate presented in the Company's direct testimony and as shown on HELCO-1406, page 1 and HELCO-1202.

Q. Did HELCO provide the Consumer Advocate with any updates to the plant retirements?

A. Yes. In response to CA-IR 187, HELCO reported the actual plant retirements from January through July 2006 as $1,650,584. HELCO later provided a preliminary year end plant retirement amount of $4,654,045 in response to CA-SIR-47, which the Consumer Advocate did not consider in its direct testimony. The actual 2006 year end amount did not change from the preliminary plant retirements amounts.

Q. Has the difference between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate accepted HELCO's recorded 2006 test year plant retirements of $4,654,045.

Joint Pole Sales

Q. What is HELCO's revised 2006 test year joint pole sales?

A. HELCO's recorded 2006 test year joint pole sales as of 12/31/06 are $797,953 as shown on HELCO-RWP-1401.

Q. How does this compare to the Consumer Advocate's estimate for joint pole sales?

A. The Consumer Advocate did not object or take issue with the $1,159,000 presented in the direct testimony and as shown on HELCO-1406, page 2.

Q. Did HELCO provide the Consumer Advocate with any updates to the joint pole sales?

A. Yes. HELCO provided a preliminary year end joint pole sales amount of $797,953 in response to CA-SIR-47, which the Consumer Advocate did not consider in its direct testimony. The actual 2006 year end amount did not change from the preliminary joint pole sale amounts.

Q. Has the difference between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate accepted HELCO's recorded 2006 test year joint pole sales of $797,953.

Property Held for Future Use

Q. What is HELCO's revised 2006 test year Property Held for Future Use ("PHFFU")?

A. HELCO's revised 2006 test year Property Held for Future Use is $129,000 as shown on HELCO-RWP-1402.

Q. How does this differ from the direct testimony?

A. The direct testimony and HELCO-1408 had forecasted that the PHFFU would be zero by the year's end. The year end estimate in direct testimony assumed that the Palani Substation would be placed in service in 2006. However, the Palani

Substation was not placed in service in 2006. As a result, the $129,000, which reflects the Palani Substation property, was added back to the PHFFU ending balance (i.e., making it $129,000 instead of $0).

Q. How does this compare to the Consumer Advocate's estimate for PHFFU?

A. The Consumer Advocate had concurred with HELCO's direct testimony with a test year average of $65,000 as shown on Exhibit CA-101, Schedule B.

Q. Has the difference between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate has accepted HELCO's adjustment of $129,000 to the ending balance. This results in a test year average of $129,000 for PHFFU.

Contributions in Aid of Construction

Q. What is HELCO's revised 2006 test year Contributions in Aid of Construction ("CIAC")?

A. The recorded CIAC for the test year is $3,011,000 as reflected on HELCO-R-1603. This includes cash receipts, in-kind receipts, transfers from advances, refunds, general excise tax payable, and amortization. Details are included in HELCO-RWP-1403, CA-SIR 51, HELCO-RWP-1404, HELCO-RWP-1405, HELCO-RWP-1403, and Exhibit 1201, respectively.

Q. How does this compare with the Consumer Advocate's estimate for CIAC?

A. The Consumer Advocate reflected $2,468,000 as the total CIAC amount for the test year, as shown on CA T-3 WP B-2.1. This resulted in an average test year balance of $58,159,000, as shown on Exhibit CA-101, Schedule B-2. In deriving the $2,468,000 total CIAC amount, the Consumer Advocate used the preliminary 12/31/06 actuals provided in CA-SIR 51 for the cash receipts ($2,478,000) and in-kind receipts ($1,471,000), and the direct testimony estimates from HELCO-1604 for the transfer from advances ($1,296,000) and amortization

($3,047,000). However, HELCO has since revised its total CIAC amount for the test year to include the final recorded amounts as of 12/31/06 for all CIAC items.

Q. Has the difference between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate has accepted HELCO's recorded total CIAC of $3,011,000 for an average test year balance of $58,431,000.

Q. In the Consumer Advocate's direct testimony, Mr. Carver had raised the issue regarding CIAC not collected for construction projects that had closed to plant in service during the test year and had included a placeholder in Exhibit CA-101, Schedule B-2. Has this issue been resolved?

A. Yes. This issue was resolved during settlement discussions between HELCO and the Consumer Advocate. As discussed by Mr. Fujioka in HELCO RT-9, the Consumer Advocate will not be pursuing this issue.

Customer Advances

Q. What are HELCO's revised 2006 test year Customer Advances?

A. The recorded Customer Advances for the test year is $3,183,000 as reflected on HELCO-R-1604. This includes cash receipts, refunds, transfers to CIAC, and general excise tax payable. Details are included in HELCO-RWP-1406, HELCO-RWP-1407, HELCO-RWP-1404, and HELCO-RWP-1406, respectively.

Q. How does this compare to the Consumer Advocate's estimate for Customer Advances?

A. The Consumer Advocate reflected $3,839,000 as the total Customer Advance amount for the test year, as shown on CA T-3 WP B-2.1. This resulted in an average test year balance of $30,517,000, as shown on Exhibit CA-101, Schedule B-2. In deriving the $3,839,000 total Customer Advance amount, the Consumer Advocate used the preliminary 12/31/06 actuals provided in CA-SIR 51 for the cash receipts ($6,413,000) and the direct testimony estimates from HELCO-1605 for the refunds ($1,278,000) and transfer to contributions ($1,296,000). However, HELCO has since revised its total Customer Advance amount for the test year to include the final recorded amounts as of 12/31/06 for all CIAC items.

Q. Has the difference between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate has accepted HELCO's recorded total Customer Advances of $3,183,000 for an average test year balance of $30,189,000.

Q. In the Consumer Advocate's direct testimony, Mr. Carver had raised the issue regarding customer advances not collected for construction projects that had closed to plant in service during the test year and had included a placeholder in Exhibit CA-101, Schedule B-2. Has this issue been resolved?

A. Yes. This issue was resolved during settlement discussions between HELCO and the Consumer Advocate. As discussed by Mr. Fujioka in HELCO RT-9, the Consumer Advocate will not be pursuing this issue.

<u>SUMMARY</u>

Q. Please summarize your testimony.

A. HELCO has revised the test year estimate with 2006 year end actuals for the following areas:

1) plant additions ($47,729,087)
2) plant retirements ($4,654,045)
3) joint pole sales ($797,953)
4) property held for future use ($129,000)
5) CIAC ($3,011,000)
6) customer advances ($3,183,000)

HELCO-R-1401 provides a progression of the Company's updates and the Consumer Advocate's direct testimony as it relates to the items above. HELCO and the Consumer Advocate have reached an agreement on all of the areas covered in my testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR ACTUALS

Line	Description	A HELCO Direct Testimony Test Year 2006 Estimate	B HELCO Updated Test Year 2006 Estimate	C Consumer Advocate Direct Testimony Test Year 2006 Amounts	D HELCO Adjusted Test Year 2006 (Actuals)	E Settlement Agreed Upon Amounts
1	Plant Additions	45,318,000	49,610,002	47,729,087	47,729,087	Note 4
2	Plant Retirements	(3,804,000)	(4,654,045)	(3,804,000)[3]	(4,654,045)	(4,654,045)
3	Joint Pole Sales	(1,159,000)	(797,935)	(1,159,000)[3]	(797,953)	(797,935)
4	Property Held for Future Use	0	NP	0	129,000	129,000
5	Contributions in Aid of Construction (CIAC)	2,784,400	1,872,500	2,748,000	2,863,901	2,863,901
6	CIAC - In-Kind	190,800	1,495,948	1,470,630	1,470,630	Note 4
7	CIAC Transferred from Advances	1,295,500[1]	NP	1,295,500	1,983,463	1,983,463
8	CIAC Refunds	0	NP	0[3]	(151,368)	(151,368)
9	Customer Advances	3,230,800[2]	4,367,500	6,413,000	7,612,752	7,612,752
10	Customer Advance Refunds	(1,277,700)	NP	(1,277,700)	(2,294,589)	(2,294,589)
11	Advances Transferred to CIAC	(1,295,500)	NP	(1,295,500)	(1,983,463)	(1,983,463)

Sources	Column A	Column B	Column C	Column E	Column D
Line 1	HELCO-1401	CA-IR 447	CA T-3 WP B-1.1	CA-SIR 51	CA-SIR 51
Line 2	HELCO-1406, p. 1	CA-SIR 47		HELCO-RWP-1401	HELCO-RWP-1401
Line 3	HELCO-1406, p. 2	CA-SIR 47		HELCO-RWP-1401	HELCO-RWP-1401
Line 4	HELCO-1408		Exhibit CA-101, Schedule B	HELCO-RWP-1402	HELCO-RWP-1402
Line 5	HELCO-1409	CA-IR 447	CA T-3 WP B-2.1	HELCO-RWP-1403	HELCO-RWP-1403
Line 6	HELCO-1409	CA-IR 447	CA T-3 WP B-2.1	CA-SIR 51	CA-SIR 51
Line 7	HELCO-1409		CA T-3 WP B-2.1	HELCO-RWP-1404	HELCO-RWP-1404
Line 8				HELCO-RWP-1405	HELCO-RWP-1405
Line 9	HELCO-1410	CA-IR 447	CA T-3 WP B-2.1	HELCO-RWP-1406	HELCO-RWP-1406
Line 10	HELCO-1410		CA T-3 WP B-2.1	HELCO-RWP-1407	HELCO-RWP-1407
Line 11	HELCO-1410		CA T-3 WP B-2.1	HELCO-RWP-1404	HELCO-RWP-1404

NP - Update Not Provided

Note 1 - Direct Testimony did not include a forecast for SSPP transfers
2 - Direct Testimony did not include a forecast for monthly SSPP receipts
3 - Consumer Advocate did not object with the value presented in HELCO's direct testimony
4 - Consumer Advocate concurs with HELCO's adjusted test year 2006 estimate (source: CA T-3 WP B-1.1 and CA T-3 WP B-2.1)

REBUTTAL TESTIMONY OF

KENNETH B.K. FONG, P.E.

PROJECT MANAGER
POWER SUPPLY ENGINEERING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Keahole CT-4 and CT-5 Cost Report

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth B. K. Fong and my business address is 820 Ward Avenue, Honolulu, Hawaii, 96814.

Q. Mr. Fong, have you previously submitted testimony in this proceeding?

A. Yes. I submitted written testimony, exhibits and supporting workpapers as HELCO T-15.

Q. What is the scope of your rebuttal testimony?

A. My testimony will cover Hawaii Electric Light Company, Inc.'s ("HELCO"):

1) Submittal of the Keahole CT-4 and CT-5 Cost Report ("Cost Report") that was previously filed with the Commission on September 7, 2005;
2) Updates to the Cost Report subsequent to submittal of my direct testimony and responses to the Consumer Advocate's information requests ("IRs") and supplemental information requests ("SIRs") regarding the Cost Report in this docket; and
3) Summary of the reasons for the cost increases as presented in the Cost Report.

KEAHOLE CT-4 AND CT-5 COST REPORT

Q. When was the Keahole CT-4 and CT-5 Cost Report filed with the Commission?

A. The Cost Report was filed on September 7, 2005.

Q. What did HELCO report as the final estimated cost for CT-4 and CT-5 in its September 7, 2005 Cost Report to the Commission?

A. In the report, the final estimated cost for CT-4 and CT-5 (including the costs for the three pre-PSD facilities placed in service prior to 2000) totaled $119.332 million and included $68.110 million for CT-4 and $51.222 million for CT-5.

A copy of the Cost Report which HELCO filed with the Commission on September 7, 2005 was provided as HELCO-1501.

UPDATES TO KEAHOLE CT-4 AND CT-5 COST

Q. Were there updates to the cost information in the September 7, 2005 Cost Report?

A. Yes. The September 7, 2005 Cost Report included actual costs through June 30, 2005 and estimates of the outstanding costs to complete CT-4 and CT-5 as explained in Exhibit V of the Cost Report. These costs were updated in HELCO T-15 to reflect the actual costs for CT-4 and CT-5 through December 31, 2005 as well as a revised estimate of outstanding costs. These updates were included as HELCO-1502 for Exhibit II, as HELCO-1503 for Exhibit III, and as HELCO-1504 for Exhibit IV. HELCO-1502, HELCO-1503, and HELCO-1504 included a side-by-side comparison of the cost estimates in the Exhibits that were filed in the September 7, 2005 Cost Report and the project's current estimated costs.

Q. How did the current total estimated costs shown in HELCO-1502 and HELCO-1503 compare to the cost estimates provided in the September 7, 2005 Cost Report?

A. In my direct testimony, the project's current total estimated cost was estimated to be $1.6 million lower than the cost estimate provided in the September 7, 2005 Cost Report. The total cost reported in HELCO T-15 for CT-4 and CT-5 (including the costs for the three pre-PSD facilities placed in service prior to 2000) was $117.724 million. This total cost included actual recorded costs of $117.689 million through December 31, 2005 and approximately $35,000 in outstanding costs for the project.

Q. Were there any updates to the Cost Report identified in response to the Consumer Advocate's IRs or SIRs?

A. Yes. Corrections related to the classification of costs in HELCO-1503 were explained and quantified in the response to CA-IR-386. These corrected classifications of costs were reflected in the HELCO T-15 response to CA-IR-447, which provided an update to the capital cost estimate for Keahole CT-4 and CT-5. The update reflected actual costs through October 31, 2006, and included a revised estimate of outstanding costs.

The revised recorded expenditures in response to CA-IR-447 through October 31, 2006 for CT-4 and CT-5 (including the costs for the three pre-PSD facilities placed in service prior to 2000) were $117,609,535, which was $80,028 lower than the recorded expenditures through December 31, 2005 of $117,689,563 (as provided in HELCO's direct testimony in HELCO-1502, 1503, and 1504.).

The response to CA-IR-447 indicated that the total revised estimated cost was $117,614,535, including an estimate of $5,000 in outstanding costs. The recorded expenditures were lower than previously reported by $80,028 primarily due to a credit of $130,000 against the engineering consultant contract which was offset by actual costs incurred in 2006 for the project.

Q. Are there any additional updates to the cost estimates previously provided in response to CA-IR-447?

A. Yes. The total actual recorded expenditures through December 31, 2006 are still $117,609,535, the same amount reported in CA-IR-447, which reported the costs through October 31, 2006. However, reclassification changes to the AFUDC amount (total increased to $21,661,087 from $21,283,972), Well Development cost (decreased to $796,465 from $1,145,511) and Supply Well Pump cost (decreased to $238,716 from $266,785) were made in HELCO-R-1502 and

HELCO-R-1503. Mr. Paul Fujioka explains these changes in HELCO RT-9. I have included updates to the cost exhibits presented in my direct testimony, which were revised in response to CA-IR-447, as exhibits to my rebuttal testimony. HELCO-R-1502 (which revises HELCO-1502 and Exhibit II of the Cost Report), HELCO-R-1503 (which revises HELCO-1503 and Exhibit III of the Cost Report), and HELCO-R-1504 (which revises HELCO-1504 and Exhibit IV of the Cost Report) contain the most current actual costs for CT-4 and CT-5 through December 31, 2006. Outstanding costs are now shown to be zero.

Q. How do these revised cost figures affect Appendix B, Reasons for Cost Increases, of the September 7, 2005 Cost Report?

A. Appendix B provided reasons for the cost increases for the project. The Appendix B references to cost figures provided in Exhibits II, III, and IV should be updated with the revised costs provided in HELCO-R-1502 for Exhibit II, HELCO-R-1503 for Exhibit III, and HELCO-R-1504 for Exhibit IV. However, the explanations for cost increases provided in Appendix B are not affected by the updated costs and are still the reasons for the cost increases.

Q. Are there any remaining outstanding costs?

A. In the HELCO T-15 response to CA-IR-447, an estimate of $5,000 in outstanding costs was included, which reflected the remaining amount to be paid to the vendor that supplied noise mitigation equipment for the project. At the time, payment of the final invoice was being withheld from the vendor until it completed warranty related work, which was expected to be done in 2007. On February 15, 2007, HELCO and the vendor, USSI, reached agreement that USSI would credit HELCO $13,500 for the installation of some of the equipment replaced as a result of the warranty claim. The net effect of this agreement is that the actual costs of the project will be reduced by about $10,000 after the final payment of $66,102 is made and accounting adjustments are made to the amount previously accrued in 2005.

Because these accounting adjustments have not been made, the actual costs in HELCO-R-1502, HELCO-R-1503, and HELCO-R-1504 do not reflect these credits or any outstanding costs.

Q. Did you include any new cost Exhibits in your rebuttal testimony?

A. Yes. HELCO-R-1505 shows the average depreciated original cost for CT-4 and CT-5 that is included in HELCO's average rate base for the 2006 test year and the net impact of CT-4 and CT-5 on HELCO's average rate base for the 2006 test year considering accumulated depreciation, accumulated deferred income taxes ("ADIT"), and state investment tax credits and unamortized state investment tax credits ("SITC") for CT-4 and CT-5, both before and after the settlement with the Consumer Advocate. (See HELCO RT-1.) These offsetting impacts were provided to me by other witnesses, including Ms. Deorna Ikeda, HELCO RT-12, and Ms. Lorie Ishii, HELCO RT-13.

SUMMARY OF COST INCREASES

Q. What is the cost for the CT-4 and CT-5 projects?

A. Referring to HELCO-R-1503, the total actual cost for CT-4 and CT-5 (including the costs for the three pre-PSD facilities placed in service prior to 2000) through December 31, 2006 is $117,609,535, or $57,737,935 higher than the estimate of $59,871,600 included in the CT-4 and CT-5 PUC applications, Docket Nos. 7048 and 7623, respectively.

Q. Why were construction costs for CT-4 and CT-5 higher than the amounts estimated in the Commission CT-4 and CT-5 dockets?

A. As shown in HELCO-R-1503, construction outside services costs were $13,070,850 higher than the estimate for construction included in the Commission dockets. Construction costs were higher for a number of reasons, which are explained in Appendix B of the Cost Report (HELCO-1501) and which are further explained by Mr. Anthony Koyamatsu in HELCO RT-15E. For example, additional costs were incurred due to normal escalation in the cost of outside contract costs since the construction work was done later than had originally been projected. Additional costs were also incurred when it became necessary to mobilize and demobilize construction crews performing pre-PSD work in 1998-1999, to commence construction in April 2002 when HELCO had obtained both the land use and air permits, and when the Third Circuit Court stopped work in September 2002.

Q. Why did HELCO incur additional costs for noise mitigation?

A. HELCO incurred additional costs to implement extensive noise mitigation countermeasures at Keahole to reduce the noise from the plant to meet the 45 dBA nighttime and 55 dBA daytime noise levels at all property boundaries required by the Settlement Agreement. As shown in HELCO-R-1503, the cost for the noise abatement work was $10,040,259. Mr. Barry Nakamoto in HELCO RT-15C and Mr. Guy Pasco in HELCO RT-15D address the noise mitigation work in more detail.

Q. Did HELCO incur additional costs for landscaping?

A. As shown in HELCO-R-1503, HELCO incurred $1,116,425 in costs categorized under landscaping. Of this amount, $903,403 was for additional landscaping to mitigate the visual impacts of the Keahole station, which was a condition of the Settlement Agreement (see response to CA-SIR-54). This work is in addition to the landscaping work HELCO did in 1998 as part of the grading contractor's work, which consisted of planting Norfolk pine trees, coconut palms, wiliwili trees, oleander, and areca palms, which cost HELCO $210,000. As explained in response to CA-SIR-54, the landscaping cost category also included $189,845 in costs for a security fence and $23,176 for work that was mis-categorized under landscaping, but was for relocating the CT-2 black start diesel engine (which was required to comply with the CT-4 and CT-5 air permit).

Q. The Consumer Advocate proposed that 50% of the $903,403 in landscaping costs be disallowed based on the contention that the costs for landscaping could have been contained at reduced levels if HELCO had rezoned Keahole, or if a different site had been selected, or if this cost had been "capped" in the Settlement Agreement. (See CA-T-3, page 98; responses to HELCO/CA-IR-310-315.) The Keahole Defense Coalition ("KDC") also suggests that costs would have been lower if HELCO had sought reclassification/rezoning of the Keahole site. (See KDC Position Statement, pages 19-20.) Do you agree with these positions?

A. No. The landscaping costs could have been more or less at a different site, depending on the site. Certain other costs (such as interconnection costs) would have been higher and also would have to be considered. If another site was selected, HELCO could have incurred similar costs to prepare the site for planting (e.g., plant the shrubs, trees and ground cover), and installing an irrigation system.

In addition, speculation as to what costs would have been incurred if HELCO had requested reclassification/rezoning of the Keahole site (i.e., under a "what if" scenario) would not be a basis for disallowing costs actually and reasonably incurred by HELCO. Mr. Warren Lee in HELCO RT-1 and Mr. Ben Tsukazaki in HELCO RT-15F address the reasons that HELCO requested an amendment to its Conservation District Use Permit, and Mr. Warren Lee addresses the reasons for the Settlement Agreement. Moreover, one of the Land Use Commission's conditions[1] for the reclassification of Keahole requires HELCO to "provide additional landscaping to mitigate the visual impacts of the Keahole Generating Station, as set forth in the Landscape Concept Plan". Further, the County also required as a condition of rezoning[2] that "Landscaping shall be included in the development plans to mitigate any potential adverse noise or visual impacts to adjacent properties". One cannot assume that these same landscaping conditions would not have applied if HELCO had rezoned the Keahole properties earlier.

Q. Was there a cap on landscaping costs in the Settlement Agreement?

A. No. The original proposal from project opponents (Keahole Defense Coalition (KDC), Ratliff, Cooper, and Department of Hawaiian Homelands (DHHL)) requested a process by which HELCO would use appropriate landscaping as approved by the Kona Outdoor Circle and the Keahole Defense Coalition. The Settlement Agreement provides that:

> "1. Visual Mitigation. HELCO will provide additional landscaping to mitigate the visual impacts of the Station, provided that HELCO, as necessary, obtains sub-leases, easements or other arrangements with owners or lessees of surrounding properties. HELCO will make a good faith effort to obtain such sub-leases, easements or arrangements as necessary and, further, will collaborate and consult with the Coalition and the Kona

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[1] See page 59 of the Land Use Commission's Findings of Fact, Conclusions of Law, and Decisions and Order for Docket No. A03-743.

[2] See County of Hawaii Ordinance Number 06-50.

Outdoor Circle in developing appropriate landscaping plans, provided, however, that DHHL shall not be required to lease or otherwise provide use of its land for these purposes."

The installed landscaping is the result of that process and was jointly developed by HELCO, KDC, DHHL and the assistance of the Kona Outdoor Circle using Hawaii Design Associates as the landscaping architect.

Q. How did HELCO estimate the cost for the landscaping?

A. As indicated in HELCO's response to CA-SIR-54, HELCO estimated that its cost for the incremental landscaping as requested by the other parties would be about $750,000, <u>subject to final construction bids</u>, based on discussions with its landscape architect, who had previously worked with the Kona Outdoor Circle, one of the parties with whom the Settlement Agreement required HELCO to collaborate and consult in developing the landscaping plan.

Q. How do the actual costs compare to the cost estimate?

A. HELCO's actual costs for the incremental landscaping were $903,403, which is consistent with the range of HELCO's original estimate. The landscaping contractor was selected through a competitive bidding process, and the actual costs reflect the market conditions and costs of plants in the Kona area at the time.

Q. What were the engineering services costs for CT-4 and CT-5?

A. As shown in HELCO-R-1503, the total engineering costs were $9,025,785, or $4,853,685 higher than the estimates in the Commission dockets.

Q. What did the engineering services cover?

A. As explained in Appendix B of the Cost Report (beginning on page 37 of HELCO-1501), engineering services for the project involved the following major categories.

<u>Owner Admin/Engineering:</u>

HELCO's engineering and administration costs for the project to support regulatory filings, permitting, legal challenges, construction, and the design of the switchyard. Costs also included HECO provided project management, design engineering, and planning costs.

<u>Plant Design Outside Engineering and Project Management:</u>

Engineering design and procurement services for the installation of CT-4 and CT-5 at Keahole were provided by Stone & Webster ("S&W").

<u>Start-Up Services:</u>

Start-up services were provided by Stone & Webster to oversee, coordinate, troubleshoot, and manage start up and commissioning of all equipment and systems associated with CT-4 and CT-5 including the water treatment systems.

Q. Why were the engineering services costs higher than the amounts estimated in the Commission dockets?

A. As explained in the Appendix B of the Cost Report, HELCO-1501, the higher than estimated engineering costs were primarily due to (1) additional material and equipment costs to inspect, rehabilitate, replace, upgrade, test, repair, and upkeep equipment and material that were previously stored because of delays in construction, (2) additional owner engineering and Stone & Webster work associated with the Settlement Agreement, primarily to support the noise abatement work for CT-4 and CT-5, (3) additional owner engineering and Stone & Webster engineering work required to support design changes made to improve operational reliability and safety, to troubleshoot and resolve unexpected equipment failures, and to conduct portions of the factory acceptance testing on-site for safety and reliability reasons, (4) owner engineering and Stone & Webster engineering to support all of the permitting and litigation for the Keahole project, (5) Stone & Webster project management and engineering work as well as HECO engineering work, to support the remobilization and demobilization of the Stone & Webster construction management and start-up personnel that occurred as a result of the mandated work stoppages, and to install temporary structures and equipment in order to safely suspend the partially erected buildings, piping systems and equipment at the time of construction work stoppages, (6) cost escalation for engineering labor, equipment rental, housing for Stone & Webster engineering personnel, and higher consultant supplied materials between the construction time assumed in the original PUC application estimate and when the actual construction took place and was completed in 2004, and (7) costs to accelerate construction of the project to put CT-4 and CT-5 into service in 2004, as discussed by Mr. Anthony Koyamatsu in HELCO RT-15E.

Q. Why were the materials costs higher than the amounts estimated in the Commission dockets?

A. As shown in HELCO-R-1503, the total materials and equipment costs for Keahole CT-4 and CT-5 is $33,389,500 or $1,679,000 higher than the estimates in the CT-4 and CT-5 dockets.

When the spare parts, freight allowance and escalation costs, which are included as separate material cost line items shown in HELCO-R-1503 (Exhibit III), are proportionally allocated among all of the material cost items, as shown in HELCO-R-1504 (Exhibit IV), higher than estimated costs were incurred primarily for the Stack Materials, Demineralizer, and Distributed Control System ("DCS"). The higher than estimated materials costs are addressed in Appendix B of the Cost Report on pages 19 to 22.

Q. What were the legal and permitting costs for CT-4 and CT-5?

A. As shown in HELCO-R-1503, legal and permitting costs for CT-4 and CT-5 are $11,042,790 or $10,086,790 higher than the estimates in the CT-4 and CT-5 dockets for this work. Included in this total are costs for:

1. Land Use permitting:

$2,079,215 in costs associated with land use permitting was incurred for CT-4 and CT-5. The permitting work included consulting services by CH2M Hill to support the CDUA application filed in 1992 with the BLNR. The permitting work also involved the preparation of the Final EIS and Revised Final EIS to support the CDUA application. Additionally, the consultant provided support for and participated in the BLNR contested case hearings and the litigation associated with permitting the project that is further described in Appendix C of the Cost Report (HELCO-1501). Mr. Ben Tsukazaki in HELCO RT-15F addresses land use permitting issues in his rebuttal testimony.

2. Legal Services for Land Use Permitting and Litigation:

$6,375,608 in legal services costs were incurred for land use permitting and related litigation for Keahole CT-4 and CT-5. These costs included legal services from:

a. Dwyer Imanaka Schraff Kudo Meyer & Fujimoto (lead counsel: Ben Kudo): The Dwyer firm was initially retained in 1993 to represent HELCO in the contested case proceeding for the CDUA before the BLNR. The Dwyer firm, and the firm of Imanaka Kudo & Fujimoto (formed in 2001 by Ben Kudo and other attorneys from the Dwyer firm) represented HELCO in proceedings before BLNR (including proceedings involving the CDUA and default entitlement and conditions relating thereto, extensions of the construction deadline, and determinations of water rights), in applications to DLNR (including applications for administrative approvals necessary in order to install noise mitigation measures), in appeals of BLNR/DLNR determinations and in numerous other litigation filed in the Third Circuit Court, and in appeals to the Hawaii Supreme Court, which are detailed in the monthly Keahole Status Reports filed in Docket No. 7623. Fees and costs incurred in litigation affecting the existing Keahole generating station have not been included in the CT-4 and CT-5 project costs and have been expensed.

b. Watanabe Ing Kawashima & Komeiji (lead counsel: Doug Ing): The Watanabe firm has advised HELCO with regard to judicial and administrative matters since about 1999, has assisted with respect to certain litigation in the Third Circuit Court, and appeals to the Hawaii Supreme Court, and has represented HELCO in the Supreme Court appeals since 2003, due to a possible conflict on the part of the Imanaka firm after former Justice Mario Ramil joined the firm in that timeframe.

c. Price Okamoto Himeno & Lum (lead counsel: Warren Price and Bob Marks): The Price firm represented HELCO in the mediated settlement of the Keahole litigation in 2003 and since that time has acted as co-counsel to Watanabe in Circuit Court and Supreme Court matters.

d. Oshima Chun Fong & Chung (lead counsel: Alan Oshima and Linnel Nishioka): Since 2003, the Oshima firm has represented HELCO before BLNR with regard to its brackish groundwater rights, assisted counsel with Circuit Court and Supreme Court matters dealing with water rights issues, and assisted HELCO in the transfer of a portion of its county potable water allocation to DHHL pursuant to the Settlement Agreement.

e. <u>Alston Hunt Floyd & Ing (lead counsel: Paul Alston)</u>: The Alston firm briefly assisted Dwyer with litigation pleadings in the 1994 timeframe.

<u>3. Air Permitting</u>:

$1,472,646 in costs related to obtaining the air permit for CT-4 and CT-5 are included in the legal and permitting costs. These costs included costs for:

a. Goodsill Anderson Quinn & Stifel to represent HELCO before the Department of Health ("DOH") and the Environmental Protection Agency ("EPA") with regard to the air permit filed in 1993 and assisted in all matters related to the 1997 Environmental Appeals Board ("EAB") proceedings. Goodsill reviewed the administrative record, worked with legal counsel from the DOH and EPA, and prepared and submitted briefs to support HELCO in the EAB proceedings.

b. Piper Marbury (later Piper Rudnick), retained in 1998 by HELCO, to assist with matters related to the Remand Order issued by the EAB and HELCO's response. Piper worked closely with HELCO and Goodsill to guide information needs to address the EAB Remand Order and provided assistance to Goodsill in preparing and submitting briefs to support HELCO in the second round of EAB proceedings.

c. Jim Clary & Associates to conduct air dispersion modeling and permit consulting services in support of the air permitting for CT-4 and CT-5. Mr. Jim Clary prepared the Keahole CT-4 and CT-5 PSD air permit application that was submitted to the DOH in January 1993. He also participated in the five air permit public hearings and provided consulting support for expert witness testimony and participated in the contested case hearings and litigation.

Mr. Scott Seu in HELCO RT-15A and Mr. Jim Clary in HELCO RT-15B provide rebuttal testimony on the air permitting issues.

4. MET and Air Data Collection:

MET and air data collection costs for Keahole CT-4 and CT-5 totaled $852,260. This included meteorological and air quality data collection to support the 1993 air permit application and 12 months of post-construction monitoring, and additional air quality data that HELCO collected as a result of the EAB remand in 1998.

5. Legal Services for Regulatory Support:

HELCO incurred $263,061 in legal services for the Goodsill firm to support all regulatory related matters and proceedings for CT-4 and CT-5.

Q. Why were labor costs higher than the amounts estimated in the CT-4 and CT-5 dockets?

A. As shown in HELCO-R-1503, labor costs were $719,740, or $542,940 higher than the estimates. HELCO labor costs were higher primarily due to higher labor costs to construct and start up the switchyard, higher training costs, higher labor costs to support the longer construction period, higher labor costs for start-up, and escalation of labor rates.

Q. What were the AFUDC costs for the CT-4 and CT-5?

A. As shown in HELCO-R-1503, AFUDC for CT-4 and CT-5 was $21,661,087, or $16,347,987 higher than the amount estimated in the CT-4 and CT-5 dockets. Mr. Paul Fujioka in HELCO RT-9, Ms. Patsy Nanbu in HELCO RT-9A and Mr. Michael Adams in HELCO RT-9B provide rebuttal testimony regarding AFUDC.

CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report			Current			Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
WAREHOUSE/SHOP BUILDING								
L3115100	HELCO Engineering	$22,420	$0	$22,420	$22,420	$0	$22,420	$0
L3115101	HECO Design	$82,650	$0	$82,650	$90,572	$0	$90,572	$7,922
L3115102	HECO System Planning	$9,872	$0	$9,872	$9,872	$0	$9,872	$0
L3115106	Outside Engineering	$26,834	$0	$26,834	$26,834	$0	$26,834	$0
L3115108	Outside EIS consultant	$76,933	$0	$76,933	$76,933	$0	$76,933	$0
L3115110	Outside Engineering for Manufacturing	$31,267	$0	$31,267	$31,267	$0	$31,267	$0
L3115129	Service & Instrument Air	$0	$0	$0	$0	$0	$0	$0
L3115152	Misc. Electrical Equipment	$17,699	$0	$17,699	$17,699	$0	$17,699	$0
L3115160	Grading/CSA Construction	$997,284	$0	$997,284	$1,055,139	$0	$1,055,139	$57,855
L3115162	Mechanical Construction	$403,094	$0	$403,094	$403,914	$0	$403,914	$820
L3115163	Tank Erection	$0	$0	$0	$0	$0	$0	$0
L3115165	Electrical Construction	$337,410	$0	$337,410	$335,523	$0	$335,523	($1,887)
L3115170	Plant Design Engineering	$267,601	$0	$267,601	$269,751	$0	$269,751	$2,150
L3115171	Construction Management	$167,319	$0	$167,319	$170,692	$0	$170,692	$3,373
L3115172	Start-up Services	$21,795	$0	$21,795	$23,399	$0	$23,399	$1,604
L3115173	Land Use Permits	$665,704	$0	$665,704	$672,406	$0	$672,406	$6,702
	Sub-total Warehouse/Shop Building	$3,127,881	$0	$3,127,881	$3,206,420	$0	$3,206,420	$78,540
	AFUDC	$332,718	$0	$332,718	$332,718	$0	$332,718	$0
	Total	$3,460,599	$0	$3,460,599	$3,539,138	$0	$3,539,138	$78,540
WATER TREATMENT SYSTEM (CT-4)								
L3191100	HELCO Engineering	$28,025	$0	$28,025	$28,025	$0	$28,025	$0
L3191101	HECO Design	$103,312	$0	$103,312	$113,213	$0	$113,213	$9,901
L3191102	HECO System Planning	$12,340	$0	$12,340	$12,340	$0	$12,340	$0
L3191105	Air Quality	$0	$0	$0	$0	$0	$0	$0
L3191106	Outside Engineering	$33,543	$0	$33,543	$33,543	$0	$33,543	$0
L3191107	Presentations - HHL	$0	$0	$0	$0	$0	$0	$0

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
L3191108	Outside EIS consultant	$96,166	$0	$96,166	$96,166	$0	$96,166	$0
L3191109	Outside PR Consultant	$0	$0	$0	$0	$0	$0	$0
L3191110	Outside Engineering for Manufacturing	$39,083	$0	$39,083	$39,083	$0	$39,083	$0
L3191111	HELCO Labor	$8,303	$0	$8,303	$1,335	$0	$1,335	($6,968)
L3191121	Steel Tank Materials	$427,571	$0	$427,571	$427,571	$0	$427,571	$0
L3191125	Fiberglass tanks	$39,053	$0	$39,053	$39,053	$0	$39,053	$0
L3191126	Miscellaneous Pumps	$90,442	$0	$90,442	$90,442	$0	$90,442	$0
L3191127	Supply Well Pump	$255,802	$0	$255,802	$238,716	$0	$238,716	($17,086)
L3191133	Demineralizer	$1,395,617	$0	$1,395,617	$1,395,627	$0	$1,395,627	$10
L3191134	Misc. Mechanical Equipment	$1,735,587	$0	$1,735,587	$1,735,587	$0	$1,735,587	$0
L3191160	Grading/CSA Construction	$896,597	$0	$896,597	$948,611	$0	$948,611	$52,014
L3191161	Well Development	$1,145,511	$120,000	$1,265,511	$796,465	$0	$796,465	($469,046)
L3191162	Mechanical Construction	$1,695,597	$0	$1,695,597	$1,699,049	$0	$1,699,049	$3,452
L3191163	Tank Erection	$39,500	$0	$39,500	$39,500	$0	$39,500	$0
L3191165	Electrical Construction	$336,154	$0	$336,154	$334,274	$0	$334,274	($1,880)
L3191166	Misc. Construction	$49,596	$0	$49,596	$49,596	$0	$49,596	$0
L3191170	Plant Design Engineering	$334,501	$0	$334,501	$337,188	$0	$337,188	$2,687
L3191171	Construction Management	$209,148	$0	$209,148	$213,364	$0	$213,364	$4,216
L3191172	Start-up Services	$27,243	$0	$27,243	$29,248	$0	$29,248	$2,005
L3191173	Land Use Permits	$521,684	$0	$521,684	$527,709	$0	$527,709	$6,025
L3191174	Miscellaneous Services	$17,181	$0	$17,181	$17,486	$0	$17,486	$305
L3191182	Legal Services	$59,633	$0	$59,633	$59,633	$0	$59,633	$0
	Sub-total Water Treatment System	$9,597,190	$120,000	$9,717,190	$9,302,826	$0	$9,302,826	($414,364)
	AFUDC	$1,574,662	$0	$1,574,662	$1,951,777	$0	$1,951,777	$377,115
	Total	$11,171,852	$120,000	$11,291,852	$11,254,603	$0	$11,254,603	($37,249)

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
FIRE PROTECTION SYSTEM (CT-4)								
L3111100	HELCO Engineering	$29,146	$0	$29,146	$29,146	$0	$29,146	$0
L3111101	HECO Design	$107,444	$0	$107,444	$117,742	$0	$117,742	$10,298
L3111102	HECO System Planning	$12,834	$0	$12,834	$12,834	$0	$12,834	$0
L3111106	Outside Engineering	$34,884	$0	$34,884	$34,884	$0	$34,884	$0
L3111108	Outside EIS consultant	$100,013	$0	$100,013	$100,013	$0	$100,013	$0
L3111110	Outside Engineering for Manufacturing	$40,647	$0	$40,647	$40,647	$0	$40,647	$0
L3111121	Steel Tank Materials	$855,143	$0	$855,143	$855,143	$0	$855,143	$0
L3111130	Fire Protection Pumps	$178,402	$0	$178,402	$188,569	$0	$188,569	$10,167
L3111160	Grading/CSA Construction	$79,111	$0	$79,111	$83,701	$0	$83,701	$4,590
L3111162	Mechanical Construction	$775,810	$0	$775,810	$777,389	$0	$777,389	$1,579
L3111163	Tank Erection	$79,000	$0	$79,000	$79,000	$0	$79,000	$0
L3111165	Electrical Construction	$167,862	$0	$167,862	$166,923	$0	$166,923	($939)
L3111170	Plant Design Engineering	$347,881	$0	$347,881	$350,676	$0	$350,676	$2,795
L3111171	Construction Management	$217,514	$0	$217,514	$221,899	$0	$221,899	$4,385
L3111172	Start-up Services	$28,333	$0	$28,333	$30,417	$0	$30,417	$2,084
L3111173	Land Use Permits	$52,810	$0	$52,810	$53,342	$0	$53,342	$532
	Sub-total Fire Protection System	$3,106,833	$0	$3,106,833	$3,142,324	$0	$3,142,324	$35,491
	AFUDC	$573,948	$0	$573,948	$573,948	$0	$573,948	$0
	Total	$3,680,781	$0	$3,680,781	$3,716,272	$0	$3,716,272	$35,491
SWITCHYARD (CT-4)								
L3303100	HELCO Engineering	$49,325	$0	$49,325	$49,325	$0	$49,325	$0
L3303101	HECO Design	$181,829	$0	$181,829	$199,256	$0	$199,256	$17,427
L3303102	HECO System Planning	$21,719	$0	$21,719	$21,719	$0	$21,719	$0
L3303106	Outside Engineering	$59,035	$0	$59,035	$59,035	$0	$59,035	$0
L3303108	Outside EIS Consultant	$235,373	$0	$235,373	$235,373	$0	$235,373	$0
L3303110	Purchase Materials	$15,623	$0	$15,623	$15,623	$0	$15,623	$0

Note: Totals may not add exactly due to rounding.

Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
L3303120	HELCO Labor	$144,269	$0	$144,269	$144,269	$0	$144,269	$0
L3303130	Outside Construction	$2,665	$0	$2,665	$2,665	$0	$2,665	$0
L3303160	Grading/CSA Construction	$1,560,654	$0	$1,560,654	$1,651,192	$0	$1,651,192	$90,538
L3303162	Mechanical Construction	$0	$0	$0	$0	$0	$0	$0
L3303163	Tank Erection	$0	$0	$0	$0	$0	$0	$0
L3303165	Electrical Construction	$120,570	$0	$120,570	$119,896	$0	$119,896	($674)
L3303170	Plant Design Engineering	$588,722	$0	$588,722	$593,451	$0	$593,451	$4,729
L3303171	Construction Management	$368,101	$0	$368,101	$375,521	$0	$375,521	$7,420
L3303172	Start-up Services	$47,948	$0	$47,948	$51,476	$0	$51,476	$3,528
L3303173	Land Use Permits	$1,041,769	$0	$1,041,769	$1,052,256	$0	$1,052,256	$10,487
L3303175	69 KV breakers	$92,641	$0	$92,641	$92,641	$0	$92,641	$0
L3303177	Misc. Switchyard Equipment	$5,255	$0	$5,255	$5,255	$0	$5,255	$0
	Sub-total Switchyard	$4,535,497	$0	$4,535,497	$4,668,952	$0	$4,668,952	$133,455
	AFUDC	$692,195	$0	$692,195	$692,195	$0	$692,195	$0
	Total	$5,227,692	$0	$5,227,692	$5,361,147	$0	$5,361,147	$133,455
COMBUSTION TURBINE (CT-4)								
L3126100	HELCO Engineering	$105,376	$0	$105,376	$105,376	$0	$105,376	$0
L3126101	HECO Design	$388,453	$55,500	$443,953	$425,683	$0	$425,683	($18,270)
L3126102	HECO System Planning	$46,399	$0	$46,399	$46,399	$0	$46,399	$0
L3126103	HECO Environmental	$746,080	$0	$746,080	$746,080	$0	$746,080	$0
L3126104	Met Data Collection	($161,557)	$0	($161,557)	($161,557)	$0	($161,557)	$0
L3126105	Air Quality Data Collection	$1,013,817	$0	$1,013,817	$1,013,817	$0	$1,013,817	$0
L3126106	Outside Engineering	$126,120	$0	$126,120	$126,120	$0	$126,120	$0
L3126108	Outside EIS Consultant	$361,584	$0	$361,584	$361,584	$0	$361,584	$0
L3126110	Outside Engineering for Manufacturing	$146,954	$0	$146,954	$146,954	$0	$146,954	$0
L3126111	HELCO Labor	$360,594	$0	$360,594	$323,631	$0	$323,631	($36,963)
L3126120	Combustion Turbine (G0007571)	$9,893,133	$41,500	$9,934,633	$9,975,847	$0	$9,975,847	$41,214

Note: Totals may not add exactly due to rounding.

Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
L3126124	Stack Materials	$1,388,876	$0	$1,388,876	$1,388,876	$0	$1,388,876	$0
L3191128	Oil/Water Separater	$122,186	$0	$122,186	$122,186		$122,186	$0
L3191129	Service & Instrument Air	$217,118	$0	$217,118	$217,118	$0	$217,118	$0
L3126130	Equipment Support Services	$130,216	$0	$130,216	$130,443	$0	$130,443	$227
L3191140	Main Transformer	$433,217	$0	$433,217	$433,217	$0	$433,217	$0
L3191141	13.8 KV Switchgear	$73,436	$0	$73,436	$73,436	$0	$73,436	$0
L3191142	480 V. Switchgear	$124,775	$0	$124,775	$124,775	$0	$124,775	$0
L3191143	480v MCC	$35,778	$0	$35,778	$35,778	$0	$35,778	$0
L3191144	Medium Voltage Power Cables	$265,487	$0	$265,487	$265,487	$0	$265,487	$0
L3191145	Distributed Control System	$1,091,456	$0	$1,091,456	$1,091,456	$0	$1,091,456	$0
L3191146	Control Panels	$166,645	$0	$166,645	$167,973	$0	$167,973	$1,328
L3191148	UPS	$238,321	$0	$238,321	$238,321	$0	$238,321	$0
L3126149	CEMS	$297,973	$0	$297,973	$297,973	$0	$297,973	$0
L3191150	Auxiliary Transformer	$30,003	$0	$30,003	$30,003	$0	$30,003	$0
L3126160	Grading/CSA Construction	$1,085,985	$353,500	$1,439,485	$1,348,986	$0	$1,348,986	($90,499)
L3126162	Mechanical Construction	$1,448,894	$434,000	$1,882,894	$1,451,844	$0	$1,451,844	($431,050)
L3126163	Tank Erection	$12,235	$0	$12,235	$12,235	$0	$12,235	$0
L3126164	Stack Erection	$707,539	$0	$707,539	$707,539	$0	$707,539	$0
L3126165	Electrical Construction	$1,335,999	$160,000	$1,495,999	$1,548,521	$0	$1,548,521	$52,522
L3126170	Plant Design Engineering	$1,257,724	$150,000	$1,407,724	$1,267,827	$0	$1,267,827	($139,897)
L3126171	Construction Management	$786,397	$50,000	$836,397	$802,249	$0	$802,249	($34,148)
L3126172	Start-up Services	$102,435	$0	$102,435	$109,973	$0	$109,973	$7,538
L3126173	Land Use Permit	$868,105	$25,000	$893,105	$875,438	$0	$875,438	($17,667)
G0007693	Noise Abatement	$4,675,513	$679,500	$5,355,013	$5,084,472	$0	$5,084,472	($270,541)
PR012596	Landscaping	$417,639	$92,500	$510,139	$559,076	$0	$559,076	$48,937

Note: Totals may not add exactly due to rounding.

Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
								$0
	Sub-total Combustion Turbine	$30,340,907	$2,041,500	$32,382,407	$31,495,137	$0	$31,495,137	($887,270)
	AFUDC	$8,437,817	$0	$8,437,817	$8,437,817	$0	$8,437,817	$0
	Total	$38,778,725	$2,041,500	$40,820,225	$39,932,954	$0	$39,932,954	($887,270)
FUEL SYSTEM (CT-4)								
L3147100	HELCO Engineering	$15,694	$0	$15,694	$15,694	$0	$15,694	$0
L3147101	HECO Design	$57,855	$0	$57,855	$63,400	$0	$63,400	$5,545
L3147102	HECO System Planning	$6,911	$0	$6,911	$6,911	$0	$6,911	$0
L3147106	Outside Engineering	$18,784	$0	$18,784	$18,784	$0	$18,784	$0
L3147108	Outside EIS Consultant	$53,853	$0	$53,853	$53,853	$0	$53,853	$0
L3147110	Outside Engineering for Manufacturing	$21,886	$0	$21,886	$21,886	$0	$21,886	$0
L3147121	Steel Tank Materials	$463	$0	$463	$463	$0	$463	$0
L3147126	Miscellaneous Pumps	$31,644	$0	$31,644	$31,644	$0	$31,644	$0
L3147160	Grading/CSA Construction	$949,338	$0	$949,338	$1,004,411	$0	$1,004,411	$55,073
L3147162	Mechanical Construction	$658,566	$0	$658,566	$659,907	$0	$659,907	$1,341
L3147163	Tank Erection	$442,580	$0	$442,580	$442,580	$0	$442,580	$0
L3147165	Electrical Construction	$108,633	$0	$108,633	$108,025	$0	$108,025	($608)
L3147170	Plant Design Engineering	$187,321	$0	$187,321	$188,826	$0	$188,826	$1,505
L3147171	Construction Management	$117,123	$0	$117,123	$119,484	$0	$119,484	$2,361
L3147172	Start-up Services	$15,256	$0	$15,256	$16,379	$0	$16,379	$1,123
L3147173	Land Use Permit	$633,701	$0	$633,701	$640,081	$0	$640,081	$6,380
	Sub-total Fuel System	$3,319,608	$0	$3,319,608	$3,392,329	$0	$3,392,329	$72,720
	AFUDC	$270,719	$0	$270,719	$270,719	$0	$270,719	$0
	Total	$3,590,327	$0	$3,590,327	$3,663,048	$0	$3,663,048	$72,720
SCADA (CT-4)								

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-4 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
L4870100	HELCO Engineering	$1	$0	$1	$1	$0	$1	$0
L4870101	HECO Design	$0	$0	$0	$0	$0	$0	$0
L4870102	HECO System Planning	$0	$0	$0	$0	$0	$0	$0
L4870106	Outside Engineering	$0	$0	$0	$0	$0	$0	$0
L4870108	Outside EIS Consultant	$0	$0	$0	$0	$0	$0	$0
L4870110	Purchase Materials	$13,142	$0	$13,142	$13,142	$0	$13,142	$0
L4870120	HELCO Labor	$25,098	$0	$25,098	$25,098	$0	$25,098	$0
L4870170	Plant Design Engineering	$0	$0	$0	$0	$0	$0	$0
L4870171	Construction Management	$0	$0	$0	$0	$0	$0	$0
L4870172	Start-up Services	$0	$0	$0	$0	$0	$0	$0
L4870173	Land Use Permits	$0	$0	$0	$0	$0	$0	$0
	Sub-total SCADA	$38,241	$0	$38,241	$38,241	$0	$38,241	$0
	AFUDC	$176	$0	$176	$176	$0	$176	$0
	Total	$38,417	$0	$38,417	$38,417	$0	$38,417	$0
Sub-total Project Components		$54,066,158	$2,161,500	$56,227,658	$55,246,229	$0	$55,246,229	($981,429)
Sub-total AFUDC		$11,882,235	$0	$11,882,235	$12,259,350	$0	$12,259,350	$377,115
TOTAL PROJECT COSTS - CT-4		$65,948,393	$2,162,000	$68,110,000	$67,505,579	$0	$67,505,579	($604,421)

Notes:
1. Sept. 7, 2005 Total Project Costs CT-4 - Outstanding Costs (Column B) and Total Estimated Costs (Column C) are rounded to the nearest thousands (000s).
2. Sum of detailed variance amounts shown on Column G totals ($566,446) vs. ($566,553). Difference of ($107) is due to Sept 7, 2005 Total Project Costs - CT-4 Total Estimated Costs (Column C) rounded to the nearest thousands (000s). $68,110,000 minus $68,109,893 = $107 .

Note: Totals may not add exactly due to rounding.

Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-5 Costs		Sep 7, 2005 Cost Report			Current			Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
WATER TREATMENT SYSTEM (CT-5)								
L3194100	HELCO Engineering	$28,025	$0	$28,025	$28,025	$0	$28,025	$0
L3194101	HECO Design	$103,312	$0	$103,312	$113,213	$0	$113,213	$9,901
L3194102	HECO System Planning	$12,340	$0	$12,340	$12,340	$0	$12,340	$0
L3194106	Outside Engr	$168,792	$0	$168,792	$168,792	$0	$168,792	$0
L3194111	HELCO Labor	$0	$0	$0	$0	$0	$0	$0
L3194121	Steel Tank Materials	$427,571	$0	$427,571	$427,571	$0	$427,571	$0
L3194125	Fiberglass tanks	$37,480	$0	$37,480	$37,480	$0	$37,480	$0
L3194126	Miscellaneous Pumps	$22,733	$0	$22,733	$22,733	$0	$22,733	$0
L3194134	Misc. Mechanical Equipment	$682,815	$0	$682,815	$682,825	$0	$682,825	$10
L3194160	Grading/CSA Construction	$896,597	$0	$896,597	$948,611	$0	$948,611	$52,014
L3194162	Mechanical Construction	$1,695,597	$0	$1,695,597	$1,699,049	$0	$1,699,049	$3,452
L3194163	Tank Erection	$39,500	$0	$39,500	$39,500	$0	$39,500	$0
L3194165	Electrical Construction	$336,154	$0	$336,154	$334,274	$0	$334,274	($1,880)
L3194170	Plant Design Engineering	$334,501	$0	$334,501	$337,188	$0	$337,188	$2,687
L3194171	Construction Management	$209,148	$0	$209,148	$213,364	$0	$213,364	$4,216
L3194172	Start-up Services	$27,243	$0	$27,243	$29,248	$0	$29,248	$2,006
L3194173	Land Use Permit	$521,684	$0	$521,684	$527,709	$0	$527,709	$6,025
L3194174	Miscellaneous Services	$17,181	$0	$17,181	$17,181	$0	$17,181	$0
L3194182	Legal Services	$59,633	$0	$59,633	$59,633	$0	$59,633	$0
								$0
	Sub-total Water Treatment	$5,620,306	$0	$5,620,306	$5,698,737	$0	$5,698,737	$78,431
	AFUDC	$710,354	$0	$710,354	$710,354	$0	$710,354	$0
	Total	$6,330,660	$0	$6,330,660	$6,409,091	$0	$6,409,091	$78,431

Note: Totals may not add exactly due to rounding.

Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-5 Costs		Sep 7, 2005 Cost Report				Current		Variance
				Total			Total	Current
		Recorded	Outstanding	Estimated	Recorded	Outstanding	Estimated	vs.
PROJECT COMPONENT		PTD 6/30/05	Costs	Costs	PTD 12/31/06	Costs	Costs	9/7/05 Costs
		(a)	(b)	(c)	(d)	(e)	(f)	(g)=(f)-(c)
FIRE PROTECTION SYSTEM (CT-5)								
L3111163	Tank Erection	$0	$0	$0	$0	$0	$0	$0
								$0
	Sub-total Fire Protection System	$0	$0	$0	$0	$0	$0	$0
	AFUDC Adjustment	$0	$0	$0	$0	$0	$0	$0
								$0
	Total	$0	$0	$0	$0	$0	$0	$0
SWITCHYARD (CT-5)								
L3304100	HELCO Engineering	$49,325	$0	$49,325	$49,325	$0	$49,325	$0
L3304101	HECO Design	$181,829	$0	$181,829	$199,256	$0	$199,256	$17,427
L3304102	HECO System Planning	$21,719	$0	$21,719	$21,719	$0	$21,719	$0
L3304106	Outside Engineering	$294,408	$0	$294,408	$294,408	$0	$294,408	$0
L3304110	Purchase Materials	$14,912	$0	$14,912	$14,912	$0	$14,912	$0
L3304120	HELCO Labor	$79,353	$0	$79,353	$79,353	$0	$79,353	$0
L3304130	Outside Construction	$2,665	$0	$2,665	$2,665	$0	$2,665	$0
L3304160	Grading/CSA Construction	$1,560,654	$0	$1,560,654	$1,651,192	$0	$1,651,192	$90,538
L3304162	Mechanical Construction	$0	$0	$0	$0	$0	$0	$0
L3304163	Tank Erection	$0	$0	$0	$0	$0	$0	$0
L3304165	Electrical Construction	$120,570	$0	$120,570	$119,896	$0	$119,896	($674)
L3304170	Plant Design Engr	$588,722	$0	$588,722	$593,451	$0	$593,451	$4,729
L3304171	Construction Management	$368,101	$0	$368,101	$375,521	$0	$375,521	$7,420
L3304172	Start-up Services	$47,948	$0	$47,948	$51,476	$0	$51,476	$3,528
L3304173	Land Use Permit	$1,041,769	$0	$1,041,769	$1,052,256	$0	$1,052,256	$10,487
L3304175	69 KV breakers	$77,821	$0	$77,821	$77,821	$0	$77,821	$0
L3304177	Misc. Switchyard Equipment	$5,255	$0	$5,255	$5,255	$0	$5,255	$0
								$0
	Sub-total Switchyard	$4,455,051	$0	$4,455,051	$4,588,506	$0	$4,588,506	$133,454

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-5 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05	Outstanding Costs	Total Estimated Costs	Recorded PTD 12/31/06	Outstanding Costs	Total Estimated Costs	Current vs. 9/7/05 Costs
		(a)	(b)	(c)	(d)	(e)	(f)	(g)=(f)-(c)
	AFUDC	$678,026	$0	$678,026	$678,026	$0	$678,026	$0
	Total	$5,133,077	$0	$5,133,077	$5,266,532	$0	$5,266,532	$133,454
COMBUSTION TURBINE (CT-5)								
L3164100	HELCO Engineering	$105,376	$0	$105,376	$105,376	$0	$105,376	$0
L3164101	HECO Design	$388,453	$55,500	$443,953	$426,456	$0	$426,456	($17,497)
L3164102	HECO System Planning	$46,399	$0	$46,399	$46,399	$0	$46,399	$0
L3164106	Outside Engr	$634,658	$0	$634,658	$634,658	$0	$634,658	$0
L3164111	HELCO Labor	$110,080	$0	$110,080	$110,080	$0	$110,080	$0
L3164120	Combustion Turbine (G0007572)	$10,159,679	$41,500	$10,201,179	$10,200,663	$0	$10,200,663	($516)
L3164124	Stack Materials	$585,872	$0	$585,872	$585,872	$0	$585,872	$0
L3164130	Equipment Support Services	$32,224	$0	$32,224	$32,451	$0	$32,451	$227
L3194140	Main Transformer	$365,556	$0	$365,556	$365,556	$0	$365,556	$0
L3194141	13.8 KV Switchgear	$52,574	$0	$52,574	$52,574	$0	$52,574	$0
L3194142	480V Switchgear	$130,430	$0	$130,430	$130,430	$0	$130,430	$0
L3194143	480V MCC	$35,778	$0	$35,778	$35,778	$0	$35,778	$0
L3194144	Medium Voltage Power Cables	$95,107	$0	$95,107	$95,107	$0	$95,107	$0
L3194146	Control Panels	$145,717	$0	$145,717	$145,717	$0	$145,717	$0
L3164149	CEMS	$266,078	$0	$266,078	$266,078	$0	$266,078	$0
L3194150	Auxiliary Transformer	$117,228	$0	$117,228	$117,228	$0	$117,228	$0
L3164160	Grading/CSA Construction	$1,085,985	$353,500	$1,439,485	$1,148,986	$0	$1,148,986	($290,499)
L3164162	Mechanical Construction	$1,448,894	$434,000	$1,882,894	$1,451,844	$0	$1,451,844	($431,050)
L3164164	Stack Erection	$677,759	$0	$677,759	$679,087	$0	$679,087	$1,328
L3164165	Electrical Construction	$1,335,999	$160,000	$1,495,999	$1,328,526	$0	$1,328,526	($167,473)
L3164170	Plant Design Engineering	$1,257,724	$150,000	$1,407,724	$1,267,828	$0	$1,267,828	($139,896)
L3164171	Construction Management	$786,397	$50,000	$836,397	$802,249	$0	$802,249	($34,148)
L3164172	Start-up Services	$102,435	$0	$102,435	$109,972	$0	$109,972	$7,537

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-5 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
L3164173	Land Use Permit	$1,613,986	$25,000	$1,638,986	$1,621,284	$0	$1,621,284	($17,702)
G0007694	Noise Abatement	$4,637,632	$679,500	$5,317,132	$4,955,787	$0	$4,955,787	($361,345)
PR012597	Landscaping	$416,373	$92,500	$508,873	$557,349	$0	$557,349	$48,476
	Sub-total Combustion Turbine	$26,634,393	$2,041,500	$28,675,893	$27,273,335	$0	$27,273,335	($1,402,558)
	AFUDC	$7,747,718	$0	$7,747,718	$7,747,718	$0	$7,747,718	$0
	Total	$34,382,110	$2,041,500	$36,423,610	$35,021,053	$0	$35,021,053	($1,402,558)
FUEL SYSTEM (CT-5)								
L3166100	HELCO Engr	$15,694	$0	$15,694	$15,694	$0	$15,694	$0
L3166101	HECO Design	$57,855	$0	$57,855	$63,400	$0	$63,400	$5,545
L3166102	HECO System Planning	$6,911	$0	$6,911	$6,911	$0	$6,911	$0
L3166106	Outside Engr	$94,523	$0	$94,523	$94,523	$0	$94,523	$0
L3166121	Steel Tank Materials	$795	$0	$795	$795	$0	$795	$0
L3166160	Grading/CSA Construction	$949,338	$0	$949,338	$1,004,411	$0	$1,004,411	$55,073
L3166162	Mechanical Construction	$658,566	$0	$658,566	$659,906	$0	$659,906	$1,340
L3166163	Tank Erection	$197,263	$0	$197,263	$197,263	$0	$197,263	$0
L3166165	Electrical Construction	$108,633	$0	$108,633	$108,025	$0	$108,025	($608)
L3166170	Plant Design Engineering	$187,321	$0	$187,321	$188,826	$0	$188,826	$1,505
L3166171	Construction Management	$117,123	$0	$117,123	$119,484	$0	$119,484	$2,361
L3166172	Start-up Services	$15,256	$0	$15,256	$16,379	$0	$16,379	$1,123
L3166173	Land Use Permit	$633,701	$0	$633,701	$640,081	$0	$640,081	$6,380
	Sub-total Fuel System	$3,042,980	$0	$3,042,980	$3,115,699	$0	$3,115,699	$72,719
	AFUDC	$265,639	$0	$265,639	$265,639	$0	$265,639	$0
	Total	$3,308,619	$0	$3,308,619	$3,381,338	$0	$3,381,338	$72,719

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components

Keahole CT-5 Costs		Sep 7, 2005 Cost Report				Current		Variance
PROJECT COMPONENT		Recorded PTD 6/30/05 (a)	Outstanding Costs (b)	Total Estimated Costs (c)	Recorded PTD 12/31/06 (d)	Outstanding Costs (e)	Total Estimated Costs (f)	Current vs. 9/7/05 Costs (g)=(f)-(c)
SCADA (CT-5)								
L4817100	HELCO Engineering	$0	$0	$0	$0	$0	$0	$0
L4817101	HECO Design	$0	$0	$0	$0	$0	$0	$0
L4817102	HECO System Planning	$0	$0	$0	$0	$0	$0	$0
L4817106	Outside Engr	$0	$0	$0	$0	$0	$0	$0
L4817110	Purchase Materials	$0	$0	$0	$0	$0	$0	$0
L4817120	HELCO Labor	$25,944	$0	$25,944	$25,944	$0	$25,944	$0
L4817170	Plant Design Engineering	$0	$0	$0	$0	$0	$0	$0
L4817171	Construction Management	$0	$0	$0	$0	$0	$0	$0
L4817172	Start-up Services	$0	$0	$0	$0	$0	$0	$0
L4817173	Land Use Permit	$0	$0	$0	$0	$0	$0	$0
								$0
	Sub-total SCADA	$25,944	$0	$25,944	$25,944	$0	$25,944	$0
	AFUDC	$0	$0	$0	$0	$0	$0	$0
								$0
	Total	$25,944	$0	$25,944	$25,944	$0	$25,944	$0
Sub-total Project Components		$39,778,674	$2,041,500	$41,820,174	$40,702,220	$0	$40,702,220	($1,117,954)
Sub-total AFUDC		$9,401,737	$0	$9,401,737	$9,401,737	$0	$9,401,737	$0
TOTAL PROJECT COSTS - CT-5		$49,180,400	$2,042,000	$51,222,000	$50,103,956	$0	$50,103,956	($1,118,044)
TOTAL PROJECT COSTS - CT-4		65,948,393	2,162,000	68,110,000	67,505,579	0	67,505,579	($604,421)
TOTAL PROJECT COSTS - CT-5		49,180,400	2,042,000	51,222,000	50,103,956	0	50,103,956	($1,118,044)
TOTAL PROJECT COSTS - CT-4 & CT-5		115,129,000	4,204,000	119,332,000	117,609,535	0	117,609,535	($1,722,465)

Note: Totals may not add exactly due to rounding.

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Total Estimated Costs for CT-4 and CT-5 by Components								
Keahole CT-5 Costs		Sep 7, 2005 Cost Report				Current		Variance
				Total			Total	Current
		Recorded	Outstanding	Estimated	Recorded	Outstanding	Estimated	vs.
PROJECT COMPONENT		PTD 6/30/05	Costs	Costs	PTD 12/31/06	Costs	Costs	9/7/05 Costs
		(a)	(b)	(c)	(d)	(e)	(f)	(g)=(f)-(c)
Notes:	1. Sept 7, 2005 Total Project Costs - CT-5 Outstanding Costs (Column B) and Total Estimated Costs (Column C) rounded to nearest thousands (000s). Sum of detailed variance amounts shown on Column G total ($1,040,794) vs. ($1,040,884). Difference of ($90) due to Sept 7, 2005 Total Project Costs - CT-5, Total Estimated Costs (Column C) rounded to the nearest thousands (000s). $51,222,000 minus $51,221,910 = $90							
	2. Sept 7, 2005 Total Project Costs - CT-4 & CT-5 amounts (Columns A, B and C) are rounded to the nearest thousands (000s).							

Note: Totals may not add exactly due to rounding.

EXHIBIT III
Page 1 of 4

CT-4 and CT-5
Comparison of Total Costs versus PUC Application Estimate

			Sep 7, 2005 Cost Report				Current Update				
		PUC Application Estimate	Actual Cost (thru 6/30/05)	Outstanding Costs	Total	Variance	Actual Cost (thru 12/31/06)	Outstand-ing Costs	Total	Variance	Variance Current vs 9/7/05 Cost
		(a)	(b)	(c)	(d)=(b)+(c)	(e)=(d)-(a)	(f)	(g)	(h)=(f)+(g)	(i)=(h)-(a)	(j)=(h)-(d)
1	**CONSTRUCTION OUTSIDE SERVICES**										
2											
3	Civil/Structual, -160	$ 5,474,900	$ 10,061,543	$ 707,000	$ 10,768,543	$ 5,293,643	$ 10,845,240	$ -	$ 10,845,240	$ 5,370,340	$ 76,697
4	Mechanical Construction, -162	$ 3,856,100	$ 8,785,018	$ 868,000	$ 9,653,018	$ 5,796,918	$ 8,802,902	$ -	$ 8,802,902	$ 4,946,802	$ (850,116)
5	Electrical Construction, -165	$ 2,533,000	$ 4,307,985	$ 320,000	$ 4,627,985	$ 2,094,985	$ 4,503,883	$ -	$ 4,503,883	$ 1,970,883	$ (124,102)
6	Tank Erection, -163	$ 685,000	$ 810,078	$ -	$ 810,078	$ 125,078	$ 810,078	$ -	$ 810,078	$ 125,078	$ -
7	Stack Erection, -164	$ 554,500	$ 1,385,298	$ -	$ 1,385,298	$ 830,798	$ 1,386,626	$ -	$ 1,386,626	$ 832,126	$ 1,328
8	Well Development, -161	$ 1,124,100	$ 1,145,511	$ 120,000	$ 1,265,511	$ 141,411	$ 796,465	$ -	$ 796,465	$ (327,635)	$ (469,046)
9	Misc Construction, -166, -130 (partial)	$ 1,000,000	$ 54,926		$ 54,926	$ (945,074)	$ 54,926		$ 54,926	$ (945,074)	$ -
10	Switchyard Construction	$ 613,900	included above	$ -	included above	$ (613,900)	included above	$ -	included above	$ (613,900)	
11	Construction Management, -171	$ 653,800	$ 3,346,372	$ 100,000	$ 3,446,372	$ 2,792,572	$ 3,413,829	$ -	$ 3,413,829	$ 2,760,029	$ (32,543)
12	Escalation	$ 1,047,800	included above		included above	$ (1,047,800)	included above	$ -	included above	$ (1,047,800)	-
13											
14	Total Construction	$ 17,543,100	$ 29,896,731	$ 2,115,000	$ 32,011,731	$ 14,468,631	$ 30,613,950	$ -	$ 30,613,950	$ 13,070,850	$ (1,397,782)
15											
16											
17	**NOISE ABATEMENT/LANDSCAPING**										
18											
19	Noise Abatement	$ -	$ 9,313,146	$ 1,359,000	$ 10,672,146	$ 10,672,146	$ 10,040,259	$ -	$ 10,040,259	$ 10,040,259	$ (631,887)
20	Landscaping	included in Civil Structural Construction	$ 834,012	$ 185,000	$ 1,019,012	$ 1,019,012	$ 1,116,425	$ -	$ 1,116,425	$ 1,116,425	$ 97,413
21											
22	Total Noise Abatement/Landscaping	$ -	$ 10,147,158	$ 1,544,000	$ 11,691,158	$ 11,691,158	$ 11,156,684	$ -	$ 11,156,684	$ 11,156,684	$ (534,474)
23											
24											

Note: Totals may not add exactly due to rounding.

CT-4 and CT-5

Comparison of Total Costs versus PUC Application Estimate

		PUC Application Estimate	Sep 7, 2005 Cost Report: Actual Cost (thru 6/30/05)	Sep 7, 2005 Cost Report: Outstanding Costs	Sep 7, 2005 Cost Report: Total	Sep 7, 2005 Cost Report: Variance	Current Update: Actual Cost (thru 12/31/06)	Current Update: Outstand-ing Costs	Current Update: Total	Current Update: Variance	Variance Current vs 9/7/05 Cost
		(a)	(b)	(c)	(d)=(b)+(c)	(e)=(d)-(a)	(f)	(g)	(h)=(f)+(g)	(i)=(h)-(a)	(j)=(h)-(d)
25	**ENGINEERING**										
26											
27	Owner Admin/Engineering,-100,101,102	$ 1,160,700	$ 2,134,982	$ 111,000	$ 2,245,982	$ 1,085,282	$ 2,352,081	$ -	$ 2,352,081	$ 1,191,381	$ 106,098
28	Plant Design OS Engineering, -170, -106	$ 2,418,300	$ 6,843,598	$ 300,000	$ 7,143,598	$ 4,725,298	$ 6,205,738	$ -	$ 6,205,738	$ 3,787,438	$ (937,861)
29	Start Up Services, -172	$ 274,700	$ 435,890	$ -	$ 435,890	$ 161,190	$ 467,967	$ -	$ 467,967	$ 193,267	$ 32,077
30	Escalation	$ 318,400	included above	$ -	included above	$ (318,400)	included above	$ -	included above	$ (318,400)	-
31											
32	Total Engineering	$ 4,172,100	$ 9,414,471	$ 411,000	$ 9,825,471	$ 5,653,371	$ 9,025,785	$ -	$ 9,025,785	$ 4,853,685	$ (799,686)
33											
34											
35	**MATERIALS**										
36											
37	Mechanical/Chemical Equipment										
38	Combustion Turbines, -120, -110 (partial)	$ 17,946,700	$ 20,332,649	$ 83,000	$ 20,415,649	$ 2,468,949	$ 20,478,550	$ -	$ 20,478,550	$ 2,531,850	$ 62,901
39	Steel Tank Materials, -121	$ 1,100,000	$ 1,711,543	$ -	$ 1,711,543	$ 611,543	$ 1,711,543	$ -	$ 1,711,543	$ 611,543	$ -
40	Stack Materials, -124	$ 798,000	$ 1,974,748	$ -	$ 1,974,748	$ 1,176,748	$ 1,974,748	$ -	$ 1,974,748	$ 1,176,748	$ -
41	Fiberglass Tanks, -125	$ 40,000	$ 76,532	$ -	$ 76,532	$ 36,532	$ 76,532	$ -	$ 76,532	$ 36,532	$ -
42	Miscellaneous Pumps, -126	$ 135,000	$ 144,820	$ -	$ 144,820	$ 9,820	$ 144,820	$ -	$ 144,820	$ 9,820	$ -
43	Supply Well Pumps, -127	$ 70,000	$ 255,802	$ -	$ 255,802	$ 185,802	$ 238,716	$ -	$ 238,716	$ 168,716	$ (17,086)
44	Oil/Water Separator, -128	$ 60,000	$ 122,186	$ -	$ 122,186	$ 62,186	$ 122,186	$ -	$ 122,186	$ 62,186	$ -
45	Service & Instrument Air, -129	$ 600,000	$ 217,118	$ -	$ 217,118	$ (382,882)	$ 217,118	$ -	$ 217,118	$ (382,882)	$ -
46	Equipment Support Services, -130 (partial)	$ 250,000	$ 162,440	$ -	$ 162,440	$ (87,560)	$ 162,893	$ -	$ 162,893	$ (87,107)	$ 453
47	Fire Protection Pumps, -130	$ 90,000	$ 178,402	$ -	$ 178,402	$ 88,402	$ 188,569	$ -	$ 188,569	$ 98,569	$ 10,167
48	Demineralizer, -133	$ 685,000	$ 1,395,617	$ -	$ 1,395,617	$ 710,617	$ 1,395,627	$ -	$ 1,395,627	$ 710,627	$ 10
49	Misc Mech/Chem Equipment/Costs, -134	$ 1,329,000	$ 2,418,402	$ -	$ 2,418,402	$ 1,089,402	$ 2,418,412	$ -	$ 2,418,412	$ 1,089,412	$ 10
50	Subtotal Mechanical/Chemical Equipment	$ 23,103,700	$ 28,990,259	$ 83,000	$ 29,073,259	$ 5,969,559	$ 29,129,715	$ -	$ 29,129,715	$ 6,026,015	$ 56,456
51											

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DOCKET NO. 05-0315
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Note: Totals may not add exactly due to rounding.

CT-4 and CT-5

Comparison of Total Costs versus PUC Application Estimate

		PUC Application Estimate	Sep 7, 2005 Cost Report				Current Update				Variance Current vs 9/7/05 Cost
			Actual Cost (thru 6/30/05)	Outstanding Costs	Total	Variance	Actual Cost (thru 12/31/06)	Outstand-ing Costs	Total	Variance	
		(a)	(b)	(c)	(d)=(b)+(c)	(e)=(d)-(a)	(f)	(g)	(h)=(f)+(g)	(i)=(h)-(a)	(j)=(h)-(d)
52	Electrical Equipment										
53	Main Transformer, -140	$ 780,000	$ 798,773	$ -	$ 798,773	$ 18,773	$ 798,773	$ -	$ 798,773	$ 18,773	$ -
54	13.8 kV Switchgear, -141	$ 121,000	$ 126,010	$ -	$ 126,010	$ 5,010	$ 126,010	$ -	$ 126,010	$ 5,010	$ -
55	480 V. Switchgear, -142	$ 370,000	$ 255,205	$ -	$ 255,205	$ (114,795)	$ 255,205	$ -	$ 255,205	$ (114,795)	$ -
56	480V MCC, -143	$ 105,100	$ 71,557	$ -	$ 71,557	$ (33,543)	$ 71,557	$ -	$ 71,557	$ (33,543)	$ -
57	Medium Voltage Power Cables, -144	$ 224,100	$ 360,593	$ -	$ 360,593	$ 136,493	$ 360,593	$ -	$ 360,593	$ 136,493	$ -
58	Distributed Control System, -145	$ 700,000	$ 1,091,456	$ -	$ 1,091,456	$ 391,456	$ 1,091,456	$ -	$ 1,091,456	$ 391,456	$ -
59	Control Panels, -146	$ 220,000	$ 312,361	$ -	$ 312,361	$ 92,361	$ 313,689	$ -	$ 313,689	$ 93,689	$ 1,328
60	UPS, -148	$ 160,000	$ 238,321	$ -	$ 238,321	$ 78,321	$ 238,321	$ -	$ 238,321	$ 78,321	$ -
61	Continuous Emission Monitor, -149	$ 435,000	$ 564,050	$ -	$ 564,050	$ 129,050	$ 564,050	$ -	$ 564,050	$ 129,050	$ -
62	Auxiliary Transformer, -150	$ 185,000	$ 147,231	$ -	$ 147,231	$ (37,769)	$ 147,231	$ -	$ 147,231	$ (37,769)	$ -
63	Misc Electrical Equip,-152,-110 (partial)	$ 672,000	$ 30,841	$ -	$ 30,841	$ (641,159)	$ 30,841	$ -	$ 30,841	$ (641,159)	$ -
64	69 KV Breakers - Switchyard, -175	$ 230,000	$ 170,463	$ -	$ 170,463	$ (59,537)	$ 170,463	$ -	$ 170,463	$ (59,537)	$ -
65	Misc Switchyard Equip,-177,-110 (partial)	$ 498,600	$ 41,044	$ -	$ 41,044	$ (457,556)	$ 91,594	$ -	$ 91,594	$ (407,006)	$ 50,550
66	Subtotal Electrical Equipment	$ 4,700,800	$ 4,207,907	$ -	$ 4,207,907	$ (492,893)	$ 4,259,785	$ -	$ 4,259,785	$ (441,015)	$ 51,878
67											
68	Spare Parts	$ 1,300,000	included above	$ -	included above	$ (1,300,000)	included above	$ -	included above	$ (1,300,000)	
69	Freight Allowance	$ 1,345,000	included above	$ -	included above	$ (1,345,000)	included above	$ -	included above	$ (1,345,000)	
70	Escalation	$ 1,261,000	included above	$ -	included above	$ (1,261,000)	included above	$ -	included above	$ (1,261,000)	-
71											
72	Total Materials	$ 31,710,500	$ 33,198,166	$ 83,000	$ 33,281,166	$ 1,570,666	$ 33,389,500	$ -	$ 33,389,500	$ 1,679,000	$ 108,334
73											
74											

Note: Totals may not add exactly due to rounding.

EXHIBIT III
Page 4 of 4

CT-4 and CT-5
Comparison of Total Costs versus PUC Application Estimate

			Sep 7, 2005 Cost Report				Current Update				
		PUC Application Estimate	Actual Cost (thru 6/30/05)	Outstanding Costs	Total	Variance	Actual Cost (thru 12/31/06)	Outstand-ing Costs	Total	Variance	Variance Current vs 9/7/05 Cost
		(a)	(b)	(c)	(d)=(b)+(c)	(e)=(d)-(a)	(f)	(g)	(h)=(f)+(g)	(i)=(h)-(a)	(j)=(h)-(d)
75	**LEGAL, PERMITTING**										
76											
77	Land Use Permitting (CH2M Hill), -108	$ 716,000	$ 1,454,008	$ -	$ 1,454,008	$ 738,008	$ 2,079,215	$ -	$ 2,079,215	$ 1,363,215	$ 625,207
78	Legal Services-Land Use Permitting/Litigation,-173,-182	$ -	$ 6,710,782	$ 25,000	$ 6,735,782	$ 6,735,782	$ 6,375,608	$ -	$ 6,375,608	$ 6,375,608	$ (360,174)
79	Legal Services Regulatory, -174	$ 100,000	$ 233,529	$ 25,000	$ 258,529	$ 158,529	$ 263,061	$ -	$ 263,061	$ 163,061	$ 4,532
80	Air Permitting, -103	$ 140,000	$ 1,184,086	$ -	$ 1,184,086	$ 1,044,086	$ 1,472,646	$ -	$ 1,472,646	$ 1,332,646	$ 288,560
81	MET & Air Data Collection, -104/5	$ -	$ 852,260	$ -	$ 852,260	$ 852,260	$ 852,260	$ -	$ 852,260	$ 852,260	$ -
82											
83	Subtotal Legal, Permitting	$ 956,000	$ 10,434,665	$ 50,000	$ 10,484,665	$ 9,528,665	$ 11,042,790	$ -	$ 11,042,790	$ 10,086,790	$ 558,125
84											
85											
86	**LABOR**										
87	HELCO Labor, -111, -120 (partial)	$ 176,800	$ 753,640	$ -	$ 753,640	$ 576,840	$ 719,740	$ -	$ 719,740	$ 542,940	$ (33,900)
88											
89	**AFUDC**	$ 5,313,100	$ 21,283,972	$ -	$ 21,283,972	$ 15,970,872	$ 21,661,087	$ -	$ 21,661,087	$ 16,347,987	$ 377,115
90											
91											
92	**GRAND TOTAL**	$ 59,871,600	$ 115,129,000	$ 4,203,000	$ 119,331,803	$ 59,460,203	$ 117,609,535	$ -	$ 117,609,535	$ 57,737,935	$ (1,722,268)

Note: 1. Sept 7, 2005 Grand Total Actual Cost (thru 6/30/05) rounded to nearest thousand (000s). Sept 7, 2005 Grand Total Outstanding Cost and Total costs are not rounded to nearest thousands (000s).

Note: Totals may not add exactly due to rounding.

CT-4 and CT-5

Comparison of Construction, Materials, and Engineering Total Costs versus PUC Application Estimate

	PUC Application Estimate (Note 1) (a)	Total Cost (as reported on 9/7/05 Report) (b)	Actual Cost (thru 12/31/06) (c)	Outstanding Costs (d)	Total (e)=(c)+(d)	Variance (f)=(e)-(a)
CONSTRUCTION OUTSIDE SERVICES						
Civil/Structual, -160	$ 5,822,672	$ 10,768,543	$ 10,845,240	$ -	$ 10,845,240	$ 5,022,568
Mechanical Construction, -162	$ 4,101,044	$ 9,653,018	$ 8,802,902	$ -	$ 8,802,902	$ 4,701,858
Electrical Construction, -165	$ 2,693,899	$ 4,627,985	$ 4,503,883	$ -	$ 4,503,883	$ 1,809,984
Tank Erection, -163	$ 728,512	$ 810,078	$ 810,078	$ -	$ 810,078	$ 81,566
Stack Erection, -164	$ 589,722	$ 1,385,298	$ 1,386,626	$ -	$ 1,386,626	$ 796,904
Well Development, -161	$ 1,195,504	$ 1,265,511	$ 796,465	$ -	$ 796,465	$ (399,039)
Miscellaneous Construction, -166, -130 (partial)	$ 1,063,521	$ 54,926	$ 54,926		$ 54,926	$ (1,008,595)
Switchyard Construction	$ 652,896	included above	included above	$ -	included above	$ (652,896)
Construction Management, -171	$ 695,330	$ 3,446,372	$ 3,413,829	$ -	$ 3,413,829	$ 2,718,499
Escalation	Note 1	included above	included above	$ -	included above	
Total Construction	$ 17,543,100	$ 32,011,731	$ 30,613,950	$ -	$ 30,613,950	$ 13,070,850

Notes:
1. For comparison purposes, the Escalation amount of $1,047,800 was reallocated to each line item in proportion of line item amount to total construction costs.

EXHIBIT IV
Page 2 of 3

	PUC Application Estimate (Note 1)	Total Cost (as reported on 9/7/05 Report)	Actual Cost (thru 12/31/06)	Outstanding Costs	Total	Variance
	(a)	(b)	(c)	(d)	(e)=(c)+(d)	(f)=(e)-(a)
ENGINEERING						
Owner Admin/Engineering,-100,101,102	$ 1,256,599	$ 2,245,982	$ 2,352,081	$ -	$ 2,352,081	$ 1,095,481
Plant Design OS Engineering, -170, -106	$ 2,618,105	$ 7,143,598	$ 6,205,738	$ -	$ 6,205,738	$ 3,587,633
Start Up Services, -172	$ 297,396	$ 435,890	$ 467,967	$ -	$ 467,967	$ 170,571
Escalation	Note 1	included above	included above	$ -	included above	$ -
Total Engineering	$ 4,172,100	$ 9,825,471	$ 9,025,785	$ -	$ 9,025,785	$ 4,853,685
Notes:						
1. For comparison purposes, the Escalation amount of $318,400 was reallocated to each line item in proportion of line item amount to total engineering costs.						
MATERIALS						
Mechanical/Chemical Equipment						
Combustion Turbines, -120, -110 (partial)	$ 20,467,868	$ 20,415,649	$ 20,478,550	$ -	$ 20,478,550	$ 10,682
Steel Tank Materials, -121	$ 1,254,529	$ 1,711,543	$ 1,711,543	$ -	$ 1,711,543	$ 457,014
Stack Materials, -124	$ 910,104	$ 1,974,748	$ 1,974,748	$ -	$ 1,974,748	$ 1,064,644
Fiberglass Tanks, -125	$ 45,619	$ 76,532	$ 76,532	$ -	$ 76,532	$ 30,913
Miscellaneous Pumps, -126	$ 153,965	$ 144,820	$ 144,820	$ -	$ 144,820	$ (9,145)
Supply Well Pumps, -127	$ 79,834	$ 255,802	$ 238,716	$ -	$ 238,716	$ 158,883
Oil/Water Separator, -128	$ 68,429	$ 122,186	$ 122,186	$ -	$ 122,186	$ 53,758
Service & Instrument Air, -129	$ 684,289	$ 217,118	$ 217,118	$ -	$ 217,118	$ (467,171)
Equipment Support Services, -130 (partial)	$ 285,120	$ 162,440	$ 162,893	$ -	$ 162,893	$ (122,227)
Fire Protection Pumps, -130	$ 102,643	$ 178,402	$ 188,569	$ -	$ 188,569	$ 85,925
Demineralizer, -133	$ 781,229	$ 1,395,617	$ 1,395,627	$ -	$ 1,395,627	$ 614,398
Miscellaneous Mech/Chem Equipment/Costs, -134	$ 1,515,699	$ 2,418,402	$ 2,418,412	$ -	$ 2,418,412	$ 902,713
Subtotal Mechanical/Chemical Equipment	$ 26,349,328	$ 29,073,259	$ 29,129,715	$ -	$ 29,129,715	$ 2,780,388

	PUC Application Estimate (Note 1)	Total Cost (as reported on 9/7/05 Report)	Actual Cost (thru 12/31/06)	Outstanding Costs	Total	Variance
	(a)	(b)	(c)	(d)	(e)=(c)+(d)	(f)=(e)-(a)
Electrical Equipment						
Main Transformer, -140	$ 889,575	$ 798,773	$ 798,773	$ -	$ 798,773	$ (90,802)
13.8 kV Switchgear, -141	$ 137,998	$ 126,010	$ 126,010	$ -	$ 126,010	$ (11,988)
480 V. Switchgear, -142	$ 421,978	$ 255,205	$ 255,205	$ -	$ 255,205	$ (166,773)
480V MCC, -143	$ 119,865	$ 71,557	$ 71,557	$ -	$ 71,557	$ (48,308)
Medium Voltage Power Cables, -144	$ 255,582	$ 360,593	$ 360,593	$ -	$ 360,593	$ 105,011
Distributed Control System, -145	$ 798,337	$ 1,091,456	$ 1,091,456	$ -	$ 1,091,456	$ 293,120
Control Panels, -146	$ 250,906	$ 312,361	$ 313,689	$ -	$ 313,689	$ 62,783
UPS, -148	$ 182,477	$ 238,321	$ 238,321	$ -	$ 238,321	$ 55,844
Continuous Emission Monitor, -149	$ 496,109	$ 564,050	$ 564,050	$ -	$ 564,050	$ 67,941
Auxiliary Transformer, -150	$ 210,989	$ 147,231	$ 147,231	$ -	$ 147,231	$ (63,757)
Miscellaneous Electrical Equipment, -152, -110 (partial)	$ 766,403	$ 30,841	$ 30,841	$ -	$ 30,841	$ (735,562)
69 KV Breakers - Switchyard, -175	$ 262,311	$ 170,463	$ 170,463	$ -	$ 170,463	$ (91,848)
Miscellaneous Switchyard Equipment, -177, -110 (partial)	$ 568,644	$ 41,044	$ 91,594	$ -	$ 91,594	$ (477,050)
Subtotal Electrical Equipment	$ 5,361,172	$ 4,207,907	$ 4,259,785	$ -	$ 4,259,785	$ (1,101,388)
Spare Parts	Note 1	included above	included above	$ -	included above	
Freight Allowance	Note 1	included above	included above	$ -	included above	
Escalation	Note 1	included above	included above	$ -	included above	
Total Materials	$ 31,710,500	$ 33,281,166	$ 33,389,500	$ -	$ 33,389,500	$ 1,679,000
Notes:						

1. For comparison purposes, the Escalation amount of $1,261,000, Spare Parts amount of $1,300,000, and Freight Allowance amount of $1,345,000 were reallocated to each line item in proportion of line item amount to total of Escalation, Spare parts and Freight costs.

Hawaii Electric Light Company, Inc.
2006 Test Year
Keahole CT-4/CT-5 Rate Base
($ Thousands)

A	B	C	D	E	F	G	H	I	J
					(B+D+E)		((B+F)/2)	((C+G)/2)	(H+I)
	12/31/2005 Net Depreciable Original Cost (A)	12/31/2005 Est Acc Def Inc Tax/SITC	2006 Additions (B)	2006 Depreciation	12/31/2006 Net Depreciable Original Cost	12/31/2006 Est Acc Def Inc Tax/SITC	2006 Test Year Average Net Depreciable Original Cost	2006 Test Year Average Est Acc Def Inc Tax/SITC	2006 Test Year Average Rate Base
Pre-PSD Common Facilities	$ 6,099	$ (1,603)		$ (405)	$ 5,694	$ (1,722)	$ 5,896	$ (1,662)	$ 4,234
PSD Common Facilities	14,617	(952)	1,166	(622)	15,162	(1,042)	14,890	(997)	13,893
CT-4	52,017	(3,226)	(696)	(2,437)	48,884	(3,530)	50,450	(3,378)	47,072
CT-5	37,781	(2,305)	(1,317)	(2,156)	34,307	(2,522)	36,044	(2,414)	33,630
	$ 110,514	$ (8,086)	$ (847)	$ (5,620)	$ 104,047	$ (8,816)	$ 107,280	$ (8,451)	$ 98,829

NOTES:

A Calculation of Net Depreciable Original Cost ($ Thousands)

	a	b	c (a+b)
	12/31/2005 Cost (CA-IR-163, p.2)	12/31/2005 Accum Depr	12/31/2005 Net Depreciable Original Cost
Pre-PSD Common Facilities	$ 7,570	$ (1,471)	$ 6,099
PSD Common Facilities	16,061	(1,444)	14,617
CT-4	54,292	(2,275)	52,017
CT-5	39,766	(1,985)	37,781
	$ 117,690	$ (7,176)	$ 110,514

B CA-SIR-44 (negative $80,030.00 plant additions less $767,184.00 retirements)

Source: Accounting Records

Settlement

Hawaii Electric Light Company, Inc.
2006 Test Year
Keahole CT-4/CT-5 Rate Base
($ Thousands)

A	B	C	D	E	F	G	H	I	J
					(B+D+E)		((B+F)/2)	((C+G)/2)	(H+I)
	12/31/2005 Net Depreciable Original Cost (A)	12/31/2005 Est Acc Def Inc Tax/SITC	2006 Additions (B)	2006 Depreciation	12/31/2006 Net Depreciable Original Cost	12/31/2006 Est Acc Def Inc Tax/SITC	2006 Test Year Average Net Depreciable Original Cost	2006 Test Year Average Est Acc Def Inc Tax/SITC	2006 Test Year Average Rate Base
Pre-PSD Common Facilities	$ 6,099	$ (1,603)		$ (405)	$ 5,694	$ (1,722)	$ 5,896	$ (1,663)	$ 4,233
PSD Common Facilities	12,895	(818)	1,166	(538)	13,524	(845)	13,210	(831)	12,379
CT-4	45,890	(2,770)	(696)	(2,139)	43,055	(2,864)	44,472	(2,817)	41,655
CT-5	33,330	(1,979)	(1,317)	(1,940)	30,072	(2,046)	31,701	(2,013)	29,688
	$ 98,214	$ (7,170)	$ (847)	$ (5,022)	$ 92,345	$ (7,477)	$ 95,279	$ (7,324)	$ 87,955

NOTES:

A Calculation of Net Depreciable Original Cost ($ Thousands)

	a	b	c (a+b)	d	e
	12/31/2005 Cost (CA-IR-163, p.2)	12/31/2005 Accum Depr	12/31/2005 Net Depreciable Original Cost	12 mil NCPIS Settlement Adjustment	Adjusted 12/31/05 Net Depreciable Original Cost
Pre-PSD Common Facilities	$ 7,570	$ (1,471)	$ 6,099		$ 6,099
PSD Common Facilities	16,061	(1,444)	14,617	(1,722)	12,895
CT-4	54,292	(2,275)	52,017	(6,127)	45,890
CT-5	39,766	(1,985)	37,781	(4,451)	33,330
	$ 117,690	$ (7,176)	$ 110,514	$ (12,300)	$ 98,214

B CA-SIR-44 (negative $80,030.00 plant additions less $767,184.00 retirements)

Source: Accounting Records

REBUTTAL TESTIMONY OF
SCOTT W. H. SEU

MANAGER
ENERGY PROJECTS DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Keahole CT-4/5 Air Permitting Issues

INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott W. H. Seu. My business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am Manager of the Energy Projects Department at Hawaiian Electric Company, Inc. ("HECO"). My educational background and experience are given in HELCO-R15A00.

Q. What is the scope of your testimony?

A. I will provide testimony that, contrary to what is alleged in the Keahole Defense Coalition's ("KDC") Position Statement in this docket, Hawaii Electric Light Company, Inc. ("HELCO" or "Company") took prudent and diligent actions to obtain the final Prevention of Significant Deterioration ("PSD") air permit for Keahole units CT-4 and CT-5 ("CT-4/5"), and that the significant delays encountered in obtaining the air permit were not predictable and were beyond HELCO's reasonable control. I will also address certain statements in CA-T-3 relating to air permitting that were made by Mr. Carver with regard to AFUDC accrual.

Q. What was your involvement with the PSD air permit application for CT-4 and CT-5?

A. I was hired by HECO in August 1993 as an environmental scientist within HECO's Environmental Department in charge of air permitting. In this capacity, I was directly responsible for coordinating all information exchanges with the state Department of Health ("DOH") and the U.S. Environmental Protection Agency Region IX ("EPA") arising during processing of the CT-4/5 PSD application. In my later roles as Principal Environmental Scientist and subsequently as HECO Environmental Department Manager, I continued my direct involvement and also oversaw the efforts of others within the Environmental Department to obtain the PSD air permit for CT-4 and CT-5, all the way through receipt of the final air permit in 2001.

Q. Mr. Seu, have you previously testified before the Public Utilities Commission on air permitting matters?

A. Yes, I served as a witness on air permitting matters in Docket No. 97-0102 (HCPC Complaint), Docket No. 97-0346 (MECO 1999 Test Year Rate Increase), and Docket No. 99-0207 (HELCO 2000 Test Year Rate Increase). In Docket No 99-0207, I submitted rebuttal testimony as HELCO RT-14b and addressed many of the same air permitting issues raised by KDC in the instant case.

<u>KEAHOLE CT-4/5 PSD AIR PERMIT DELAYS</u>

Q. What was HELCO's original expectation on PSD permit approval timing at Keahole?

A. At the time HELCO submitted its application submittal in January 1993, the Company was using an 18-month approval timeframe for planning purposes. It anticipated issuance of an effective PSD permit in mid-1994 to support installation of the units in late 1994.

Q. What was the basis for the 18-month planning estimate?

A. The basis was the utility's past permitting experience with combustion turbines. For Keahole CT-2 in 1989, Maalaea unit M14 in 1991, and Maalaea M16 and Puna CT-3 in 1992, PSD permits for combustion turbines took from 14 to 23 months to be approved. Because the average timeframe for approval of these four permits was 18 months and three weeks, 18 months was a reasonable timeframe to use for planning purposes for Keahole CT-4 and CT-5.

Q. Did HELCO ever obtain any input from the DOH on this assumption?

A. HELCO made the DOH aware of its 18-month planning assumption, but the DOH never provided any formal agreement or disagreement. However, the 18-month estimate was shown to be reasonable when the new State Covered Source air regulations codified in Section 11-60.1 of the Hawaii Administrative Rules ("HAR") were finalized in November 1993, just ten months after the Keahole PSD application was submitted. HAR § 11-60.1-83 states that the DOH shall approve, conditionally approve, or deny a PSD application within 12 months after receipt of a complete application.

Q. When was final approval of the CT-4/5 PSD air permit obtained?

A. The CT-4/5 PSD air permit became effective in November 2001. This was almost a full nine years after the initial permit application was filed in January 1993.

Q. What were the primary causes of delay?

A. There were delays due to the following events:

1) the development and promulgation of the new state Covered Source air regulations in 1993;

2) the DOH decision in September 1994 to incorporate new meteorological data into the CT-4/5 air quality analysis;

3) the EPA's change in position in November 1995 regarding the use of selective catalytic reduction ("SCR") as best available control technology ("BACT");

4) the petitions filed against the final PSD permit in November and December 1997 to the EPA's Environmental Appeals Board ("EAB"),

including a petition filed by KDC, and the EAB's partial remand order in November 1998;

5) the EPA's determination in December 1999 that additional air quality data needed to be gathered to support the issuance of the air permit; and

6) the petitions filed against the final PSD permit to the EAB in September 2001, again including a petition by KDC.

I will discuss each of these events in turn.

PERMITTING DELAYS DUE TO
NEW STATE AIR REGULATIONS

Q. How did the promulgation of the new covered source air regulations cause delays to the Keahole PSD air permit?

A. Through 1993, the DOH permitting staff was heavily involved in writing the new Covered Source air regulations. The Company's observation was that the DOH was unable to fully devote itself to the processing of permits until after the new regulations were finalized on November 26, 1993. The new regulations also required HELCO to file additional information in February 1994 that added to the DOH's review.

Q. What additional information was required from HELCO?

A. After promulgation of the new Covered Source air regulations, HELCO was required to file a covered source permit application for CT-4 and CT-5 and did so on February 1, 1994. Although the initial January 1993 air permit application had previously been deemed complete on June 14, 1993, the covered source permit application had to be reviewed for completeness under the new regulations. It was deemed complete by the DOH for PSD purposes on February 25, 1994, and for covered source purposes on May 13, 1994. These additional completeness determinations did not mean that the permit review began all over again, but they nonetheless added additional review requirements.

SEPTEMBER 1994 DOH DECISION TO INCORPORATE
NEW METEOROLOGICAL DATA INTO PERMIT REVIEW

Q. Please explain the circumstances and impacts of the DOH's decision to incorporate new meteorological data into the Keahole PSD permit review.

A. On July 13, 1994, the DOH sent a preliminary draft permit to the EPA for review, followed by issuance of a draft permit on August 5, 1994. A public hearing was scheduled on September 12, 1994. Prior to the hearing, on September 8, 1994, HELCO submitted an application to modify the existing Keahole CT-2 PSD air permit in accordance with an agreement with the State Attorney General's office. A principal component of a PSD application is an ambient air quality impact analysis that uses a year's worth of meteorological data. The CT-2 application contained an analysis based on meteorological data that had been gathered by HELCO in the 1993 to 1994 timeframe, subsequent to the initial January 1993 filing of the Keahole CT-4 and CT-5 PSD air permit application. Despite the previous completeness determinations that had been granted to the CT-4 and CT-5 PSD application, the DOH unexpectedly decided and announced at the September 12, 1994 public hearing that the more recent meteorological data from the CT-2 application would be required for the CT-4 and CT-5 permit application.

Q. What was the impact of this decision?

A. A new air quality modeling analysis would need to undergo technical review by the DOH. When this was done, the DOH would need to revise the draft permit's ambient air quality impact report, reissue a draft permit, and hold another public hearing.

Q. How much delay was experienced as a result of the DOH decision to incorporate the new data?

A. The draft permit was reissued on March 9, 1995, and a second public hearing was held on April 10, 1995. This was seven months after the first public hearing was held.

NOVEMBER 1995 EPA CHANGE IN POSITION ON BEST AVAILABLE CONTROL TECHNOLOGY

Q. You identified the EPA's change in position on BACT in November 1995 as another primary cause of delay to the Keahole air permit. Please explain the circumstances and impact of this event on the CT-4/5 PSD air permit schedule.

A. In addition to an ambient air quality impact analysis, a critical component of a PSD air permit application is an assessment of BACT. The applicant is required to determine BACT for certain emissions following the EPA methodology, and to incorporate the controls into the project. BACT for nitrogen oxides ("NO_x") emissions proposed in the 1993 CT-4/5 PSD application was the use of water injection. This technology was consistent with the final PSD permits issued by the EPA and the DOH for Maui Electric Company's ("MECO") Maalaea units M14 and M16 in 1991 and 1992, and HELCO's Puna unit CT-3 in 1992. Following the second public hearing in April 1995, the DOH transmitted a proposed final permit incorporating water injection to the EPA for its approval. By letter to the DOH dated November 14, 1995, the EPA declined to approve the final permit, stating that it had adopted the position that rather than water injection, SCR should be considered BACT for Keahole CT-4/5 when operated in combined cycle.

Q. Did the EPA consider SCR as BACT for Keahole CT-4/5 when operated in simple cycle?

A. No. The EPA stated that the DOH could use its discretion with regard to requiring SCR for simple cycle operation.

Q. Did the EPA ever indicate to HELCO prior to November 1995 that it had concerns over the proposed NO_x BACT?

A. No. There was no indication prior to November 1995 that the EPA would disagree on the BACT proposed in the Keahole PSD permit application. In fact, in its official comment letter dated September 15, 1994 to the DOH, the EPA stated that "it concurs with the requirements and conditions contained in the PSD permit proposed by [DOH]." With respect to NO_x BACT, the EPA merely had recommended that the permit be clarified "to require installation of SCR <u>provided</u> it is successfully demonstrated by the MECO study." (emphasis added) This recommendation was consistent with the previous BACT determinations for M14, M16, and CT-3.

Q. Did HELCO take steps to address the EPA's change in position?

A. Yes. Meetings were held with the EPA for several months following its change of position. When it became clear that there was disagreement between HELCO and the EPA on what was technically and economically feasible as BACT, the EPA suggested in a meeting on March 22, 1996 that HELCO "net out" of federal NO_x BACT requirements. To net out requires that net NO_x emissions increases at the Keahole facility be kept below the EPA's significant NO_x emissions increase threshold upon startup of CT-4 and CT-5. HELCO agreed with this approach, and on April 3, 1996, requested a modification to its proposed covered source permit that would limit the net NO_x emissions increase at Keahole. After further discussions with the EPA and the DOH, HELCO submitted a detailed NO_x netting proposal to the DOH and the EPA on July 2, 1996. This netting proposal was ultimately accepted by the EPA and the DOH and incorporated into the draft PSD air permit.

Q. Did the EPA raise any other concerns regarding BACT for other types of emissions?

A. By letter dated April 17, 1996 to the DOH, the EPA requested that the DOH re-evaluate whether naphtha fuel could be used at Keahole as BACT for sulfur dioxide ("SO_2"). By letter dated May 24, 1996, HELCO provided detailed information to the DOH showing that the use of naphtha in CT-4 and CT-5 would be economically infeasible and should not be considered BACT for SO_2. The DOH and the EPA ultimately concurred with HELCO's SO_2 BACT determination.

Q. What was the schedule impact of the EPA's change in position on NO_x BACT?

A. A draft permit was re-issued incorporating the NO_x net out and a third public hearing was held on March 3, 1997. After responding to comments, the DOH again sent a proposed final PSD air permit to the EPA for its approval. On October 15, 1997, the EPA approved the final PSD air permit and the DOH issued the final permit to HELCO by letter dated October 28, 1997. Considering that the proposed final permit had first been sent to the EPA in late 1995, the EPA's unanticipated change in position on NO_x BACT in November 1995 resulted in a two-year delay.

1997 FILING OF PETITIONS AGAINST PERMIT TO EPA ENVIRONMENTAL APPEALS BOARD AND 1998 EAB ORDER

Q. What happened following issuance of the final PSD air permit in October 1997?

A. In November and early December 1997, nine petitions were filed against the Keahole permit to the EAB. The petitions were filed by Kawaihae Cogeneration Partners ("KCP"), KDC, and seven private citizens. With the filing of the petitions, permit effectiveness was stayed and construction of CT-4 and CT-5 could not begin.

Q. What was the history of the filing of such appeals with respect to Hawaii air permits?

A. As of 1993, no appeals had ever been filed against a utility air permit in Hawaii. HELCO, MECO and HECO had successfully obtained eight PSD air permits for various power plants across the islands, including those for the combustion turbines M14, M16, and CT-3. In fact, prior to 1993 there had been only one appeal of a PSD air permit in Hawaii, against a proposed coal-fired fluidized bed combustor at a sugar plantation on Maui, and that appeal had been denied.

Q. When did the EAB issue a determination on the petitions, and what was its determination?

A. The EAB issued its determination on November 25, 1998 ("1998 EAB Order").[1] The EAB denied appeals of the permit that were based on challenges to the DOH's use of a netting analysis with respect to NO_x emissions, and the DOH's determination of SO_2 BACT. However, the EAB concluded that the DOH had not adequately responded to comments that had been made during the public

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[1] *In re Hawaii Electric Light Co., Inc.*, 8 E.A.D 66 (EAB 1998), U.S. Environmental Protection Agency Environmental Appeals Board, http://www.epa.gov/eab/.

comment period that data relating to certain ambient air concentrations were outdated or were measured at unrepresentative locations.

The EAB remanded the proceedings and directed the DOH to reopen the permit for the limited purposes of (1) providing an updated air quality impact report incorporating current data on SO_2 concentrations and particulate matter and (2) providing a sufficient explanation of why carbon monoxide and ozone data were reasonably representative, or performing a new air quality analysis based on data shown to be representative. The EAB directed the DOH to then accept and respond to public comments on the DOH's decisions with respect to these issues and ruled that any further appeals of its decision would be limited to the issues addressed on remand.

Q. Was the EAB partial remand expected?

A. No. In HELCO's view, the air quality data used in the Keahole CT-4/5 permit application were technically sound. Mr. James Clary provides more detailed discussion of the basis for this in his rebuttal testimony at HELCO RT-15B. The data had been extensively reviewed by both the DOH and the EPA, and issuance of the final air permit to HELCO in 1997 affirmed its use. Furthermore, the very same air quality data had been used in KCP's air permit, which had successfully been upheld by the EAB against appeals in 1997. HELCO provided these arguments and others to the EAB. As stated in the 1998 EAB Order, however, the reason why the permit was not upheld was that the EAB felt the DOH had not adequately responded to public comments regarding the air quality data. According to the 1998 EAB Order, the DOH had the discretion to accept the air quality data used by HELCO, provided it adequately justified its decisions in the administrative record.

Q. *What actions did HELCO take to respond to the 1998 EAB Order?*

A. HELCO filed a motion for reconsideration to the EAB on December 7, 1998. While the motion was being considered, HELCO proceeded in January 1999 to install a new ambient air quality monitoring station at its Huehue Substation to gather data. Although HELCO felt the data used to support the permit to that point were technically sound, HELCO believed that gathering additional data at Huehue would be the most expeditious method of addressing the concerns raised by the petitioners in case the motion for reconsideration was denied by the EAB. The EAB did in fact deny HELCO's motion in March 1999.

The Huehue Substation was selected with input from the DOH. HELCO gathered data at Huehue, and in close consultation with the DOH, compiled data from other Hawaii monitoring stations that would be suitable to respond to the issues raised in the 1998 EAB Order. In HELCO RT-15B, Mr. Clary provides more details of this work which led to the development of a response to the 1998 EAB Order by the DOH. On August 9, 1999, the DOH published public notice and requested public comment on a proposed DOH response to the 1998 EAB Order. Notice was again published on August 30, 1999 due to errors made by the DOH in the initial public notice process. A public hearing to consider the DOH's draft EAB response was held on October 7, 1999, in Kona.

DECEMBER 1999 EPA DETERMINATION ON
ADDITIONAL AIR QUALITY DATA

Q. *What happened after the October 1999 public hearing?*

A. Following the October hearing and comment period, HELCO felt that all issues could be adequately addressed and the permit reissued. However, by letter dated December 9, 1999 to the DOH, the EPA indicated its position that additional air quality monitoring data should be collected to support issuance of the final Keahole CT-4/5 PSD air permit.

As described in HELCO RT-15B by Mr. Clary, prior to the October 1999 hearing, the Company had worked very closely with the DOH staff to identify acceptable air quality data to respond to the 1998 EAB Order. The data were from HELCO's Huehue Substation (ozone), and State air monitoring stations at the Keahole airport (PM_{10}), Konawaena (SO_2), and Kapolei (CO). Although according to its letter the EPA adopted this position after reviewing Supplement C of the DOH's Ambient Air Quality Impact Report that was issued in August 1999, HELCO understood from its discussions with the DOH that the EPA reviewed the information in Supplement C with the DOH prior to August 1999 and did not object to the proposed data. By letter dated January 5, 2000, the DOH concurred with the EPA's position and directed the Company to gather additional air quality data. This was yet another unanticipated change of a prior DOH determination.

Q. What actions did HELCO take to respond to this determination?

A. Notwithstanding HELCO's position that the data described in Supplement C was valid for supporting issuance of the final permit, HELCO secured an additional air quality monitoring site at the end of Kakahiaka Street in the Kona Palisades area, the location of which was approved by the DOH by letter dated March 1, 2000. HELCO collected two months of air quality monitoring data at this site, in accordance with the EPA and DOH directives. HELCO's analysis showed that the data further supported issuance of the Keahole CT-4/5 PSD air permit. In HELCO RT-15B, Mr. Clary explains in greater detail the additional air quality monitoring at Kakahiaka Street, and HELCO's analysis of this data which confirmed the Company's prior conclusions supporting permit issuance.

In December 2000, the DOH affirmed this conclusion in its issuance of a revised draft response to the 1998 EAB Order, identified as Supplement D to the Ambient Air Quality Impact Report, which incorporated the additional air quality monitoring data gathered by HELCO at Huehue Substation and Kakahiaka Street. The draft air permit and supplemented air permit package were made available for public comment, and a fifth public hearing was held in March 2001.

Q. What amount of delay was caused by the EPA decision to require additional data in 1999?

A. Considering the amount of time between the fourth and fifth public hearings, seventeen months was added to the schedule.

2001 PERMIT ISSUANCE AND FILING OF PETITIONS AGAINST PERMIT TO EPA ENVIRONMENTAL APPEALS BOARD

Q. What happened subsequent to the March 2001 public hearing?

A. The DOH responded to the public comments and transmitted the proposed final permit to the EPA for its review. Following the EPA's approval of the permit, in August 2001 the DOH issued the final air permit to HELCO. The air permit did not immediately take effect, however, as six petitions for appeal were filed at the EAB later that month.

Q. Did KDC file a petition to the EAB?

A. Yes it did. KDC alleged that HELCO's air quality impact results for the project were erroneous. A separate petition was also filed by KDC's attorney Michael Matsukawa and KDC member Peggy Ratliffe.

Q. What did HELCO do to respond to these petitions?

A. On October 15, 2001, HELCO and the DOH jointly filed a Memorandum of Law in Opposition to Petitions with the EAB. HELCO also filed motions requesting status as an intervenor in the EAB proceeding and requesting that the proceeding be expedited.

Q. Did KDC respond to HELCO's motions?

A. Yes. KDC and other petitioners including Michael Matsukawa filed objections to HELCO's motion to intervene and motion for expedited review. KDC alleged that HELCO's motion for expedited review should not be granted based on its claims that HELCO was responsible for causing much of the delay in the permitting process by not complying with the intent of the Clean Air Act. Prior to receiving the objections however, the EAB had already issued an order granting HELCO's motions to intervene and expedite the proceedings.

Q. When did the EAB issue its decision on these petitions, and what was the EAB's ruling?

A. The EAB issued its decision on the petitions on November 27, 2001 ("2001 EAB Order").[2] The 2001 EAB Order denied review of the petitions on all grounds, upholding HELCO's air quality impact results. With this ruling, the Keahole CT-4/5 PSD air permit was deemed effective. Incidentally, in the 2001 EAB Order, the EAB stated that the objections raised against HELCO's motion to intervene and motion to expedite the proceedings were without merit, and that KDC's objections were "unpersuasive." (2001 EAB Order, page 223, n. 7.)

Q. What added delay did the 2001 EAB petitions cause?

A. Had no petitions been filed with the EAB, the PSD air permit would have become effective 30 days after issuance to HELCO, or in late August 2001. The 2001

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[2] *In re Hawaii Electric Light Co., Inc.*, 10 E.A.D. 219 (EAB 2001), U. S. Environmental Protection Agency Environmental Appeals Board, http://www.epa.gov/eab/.

EAB Order affirmed the permit in late November 2001. Thus, the EAB petitions added three months more delay.

Q. Did the 2001 EAB Order complete the Keahole air permit process?

A. Effectively, yes, although KDC filed a motion for reconsideration to the EAB on December 7, 2001. The EAB denied KDC's motion for reconsideration on January 29, 2002.

KEAHOLE DEFENSE COALITION'S POSITION REGARDING THE KEAHOLE CT-4/5 AIR PERMIT

Q. What is KDC's position regarding the CT-4/5 air permit?

A. KDC is challenging HELCO's full recovery of air permitting costs for the CT-4/5 project, based on claims that the costs were increased due to "predictable delays" caused by HELCO's "decision to use hastily assembled data for its air permit application...and to refuse using SCR." (KDC Position Statement, page 39.)

Q. Given the information presented above explaining the CT-4/5 air permit delays, how do you respond to the charge that HELCO used "hastily assembled data for its air permit application"?

A. KDC's position is without merit. As I have described, the numerous starts and stops to the permit were not predictable, nor were they caused by HELCO making any decisions to cut corners. In fact, throughout the permitting timeline, HELCO presented extensive data and air quality analyses to support its application. Based on this data, HELCO received favorable regulatory agency determinations, as exhibited by the DOH's ambient air quality impact reports and the issuance of draft and final permits. On occasion, however, these agency determinations were unexpectedly called into question by the DOH, the EPA, or the EAB.

HELCO provided solid data and analyses in support of its initial permit application, leading to a completeness determination and the issuance of a draft permit by the DOH. A last minute decision by the DOH to incorporate new data, data collected by HELCO for another application, caused the first draft permit to be delayed. Following its review of the new data, a second draft permit was issued by the DOH. During the first public comment period, the EPA officially concurred with the permit conditions, but after the second public comment period, the EPA changed its position on NO_x BACT. Following rework to address the EPA's concerns on BACT, the DOH issued a third draft permit and the DOH and the EPA ultimately granted a final permit to HELCO.

This final permit was challenged, and the EAB remanded the air permit in part to the DOH. The EAB upheld the permit with regard to HELCO's NO_x netting and SO_2 BACT. The EAB remanded the permit in part for further review of issues concerning the air quality data used in the DOH's ambient air quality impact report. Significantly, the EAB did not find fault with the data submitted by HELCO. The EAB's Order has a lengthy discussion of issues regarding the Ambient Air Quality Impact Analysis. According to the EAB, "we find that DOH's responses to comments on the issue of currentness of the SO_2 and particulate matter data were not adequate." (1998 EAB Order, page 101.) Similarly with respect to the location representativeness of the CO and O_3 data, the EAB concluded that the DOH's responses to comments were not adequate. (1998 EAB Order, page 104.) The permit was remanded on this basis, not because the HELCO data was found to be flawed.

The EAB therefore directed the DOH to (1) provide an updated air quality impact report incorporating the new data; and (2) either provide a sufficient explanation of why the carbon monoxide ("CO") and ozone ("O_3") data used in its air quality analysis were reasonably representative of the air quality in the area to be affected by the expansion, or to perform a new air quality analysis based on either on-site data or other data shown to be representative of the air quality in the area to be affected by the expansion. Thus, KDC's statement that "In November 1998, the United States Environmental Protection Agency Appeals Board ruled that the Company's supporting air data was inadequate and ordered the Company to obtain further data to support the Company's air permit application" (KDC Position Statement, page 11.) is erroneous. The EAB did not rule that HELCO's data was inadequate, nor did it order that new data must be collected.

After much effort by HELCO to gather six months of additional air quality data from the Huehue Substation monitoring station as approved by the DOH, the DOH accepted the data and issued a draft response to the EAB remand. As the DOH had approved the site, HELCO could not have anticipated that the EPA would recommend additional monitoring from another station to corroborate the results. Following a fifth public comment period, the EAB reissued and upheld the permit. At no time during the process did the DOH, the EPA or the EAB suggest that HELCO used "hastily assembled data for its air permit application."

Q. How do you respond to KDC's statements regarding SCR?

A. The KDC Position Statement falsely states that HELCO "denied" that SCR was BACT even though "the United States Environmental Protection Agency had stated that SCR is best available control technology for CT-4 and CT-5." (KDC Position Statement, page 12.) As I described earlier, the EPA and the DOH affirmed HELCO's initial BACT position through issuance of the first draft permit in 1994. It was not until November 1995 that the EPA expressed a change in its position, at which time HELCO worked diligently with the EPA to address its concerns, ultimately leading to the NO_x netting approach. Even with the incorporation of the NO_x netting approach, the subsequent permit continued to contain provisions subjecting Keahole CT-4/5 to possible retrofit of SCR, subject to the final outcome of the MECO SCR Demonstration Project.

Q. Did KDC challenge HELCO's NO_x netting approach?

A. Yes. Petitions, including one by KDC, were filed to the EAB against HELCO's NO_x netting approach in November and December 1997. In the 1998 EAB Order, the EAB denied the petitions with respect to the NO_x netting issues, stating that KDC and the other petitioners had "failed to sustain their burden of showing clear error or that review by this Board is otherwise warranted with respect to the NO_x netting analysis…." (1998 EAB Order, page 71.) KDC's statement that "In November 1998, the EPA Appeals Board directed the Company to obtain more representative data to support its air permit application, leaving the issue of SCR unresolved" (KDC Position Statement, page 20, emphasis added), is not correct.

Q. Was the EPA's concern regarding NO_x emissions from CT-4/5 ultimately addressed to its satisfaction, without use of SCR?

A. Yes it was.

CONSUMER ADVOCATE'S PRE-SETTLEMENT POSITION REGARDING SUSPENSION OF ACCRUAL OF AFUDC, RELATIVE TO AIR PERMIT

Q. Why did the Consumer Advocate take the position that accrual of AFUDC should have been suspended in September 1994?

A. Mr. Carver maintained that: "[S]ignificant facts were known in the September 1994 time frame that consistently signaled further delays in the permitting and construction schedule. At that time, HELCO knew or should have known that limited physical construction would be allowed for a potentially protracted period, which should have reasonably resulted in a decision to suspend AFUDC capitalization until the necessary permits were received allowing construction activities to proceed on a reasonably planned an progressive schedule of activities." (CA-T-3 at 73-74.)

Q. Did any of the factual circumstances to which he referred relate to air permitting?

A. Yes. One of two factual circumstances at the time that Mr. Carver cited relates to air permitting:

"In September 1994, DOH held public hearings regarding the air permit for the Keahole CT-4, CT-5 and ST-7 projects. At about this same time, HELCO submitted a request to modify the air permit for the Keahole CT-2 unit, using more current meteorological data than was presented in the application for the planned generation additions. Because of the availability of more recent data, DOH concluded that a second public hearing was necessary." (CA-T-3, page 72.)

Q. What was the status of HELCO's CT-4/5 air permit at that time?

A. HELCO had worked very closely with DOH for over a year and a half in successfully justifying issuance of the draft air permit with the original meteorological data set.

Q. Did HELCO anticipate that submitting the CT-2 permit modification application would be problematic for the CT-4/5 permit, given the use of a different meteorological data set?

A. No. It was within the DOH's discretion to continue to process the Keahole CT-4/5 permit application on the basis of the initial data set.

Q. Did HELCO expect a protracted period of delay as a result of DOH's determination that a second public hearing should be held?

A. No. Although DOH required HELCO to prepare a new ambient air quality impact analysis using the meteorological data from the CT-2 permit application, HELCO considered that this would add several months, but not years, to the CT-4/5 air permit process. This was based on HELCO's estimates that it would take approximately two to three months to prepare the updated analysis as well as respond to comments from the first public hearing, followed by two months for DOH to review the analysis and prepare a revised draft permit and air quality impact report, and one month for the second public comment period. In actuality, as described earlier, the second public hearing took place in April 1995, seven months after the first hearing.

The further delays encountered in obtaining the final air permit needed to install CT-4 and CT-5 at Keahole were extraordinary, and were beyond HELCO's reasonable control. In addition to the DOH's discretionary decision to require use of the CT-2 meteorological data, EPA's change in position on NO_x BACT in November 1995, the partial remand order by the EAB in November 1998, and the EPA's decision to require additional air quality data in December 1999, were not expected. Through it all, HELCO took prudent and diligent actions to obtain the final PSD air permit, and HELCO could not have reasonably anticipated the substantial delays in the PSD air permit process.

CONCLUSION

Q. Please summarize HELCO's actions to obtain the PSD air permit for the Keahole CT-4/5 project?

A. HELCO acted prudently in applying for, and eventually obtaining the air permit. Over the almost nine years it took to obtain the permit, the Company dealt with the promulgation of new air regulations, a significant change in the EPA's position on NO_x BACT, and constant challenges to the very end from Keahole project opponents such as KDC and KCP. HELCO also received numerous favorable determinations by regulatory agencies indicating that its permitting methodologies and conclusions were sound, only to see additional questions raised by the agencies. HELCO responded diligently to address all of the issues, and ultimately prevailed in obtaining the air permit.

Q. Did the additional data collected change the evaluation of the air quality impact of this project?

A. No. As shown in Exhibit HELCO-R-15B02 attached to Mr. Clary's testimony, modeled air quality impacts did not change significantly with the consideration of additional data. Most importantly, at no time did the air quality impacts of this project approach the State Ambient Air Quality Standards.

Q. Did the additional data collected change the permit conditions?

A. No. Changes to the permit conditions were made with regard to NO_x netting, but no permit conditions were changed as a result of the additional air quality data collected.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY INC.

SCOTT W. H. SEU, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
Current Position:	Manager Energy Projects Department Hawaiian Electric Company, Inc.
Education:	Bachelor of Science in Mechanical Engineering Stanford University, 1987 Master of Science in Mechanical Engineering Stanford University, 1988
Other Qualifications:	Licensed Professional Engineer State of Hawaii, Mechanical Branch
Prior Experience:	HAWAIIAN ELECTRIC COMPANY, INC. 2003 - 2004 Manager Customer Installations Department Hawaiian Electric Company, Inc. 1998 - 2002 Manager Environmental Department Hawaiian Electric Company, Inc. 1997 - 1998 Principal Environmental Scientist Environmental Department Hawaiian Electric Company, Inc.

Experience (cont'd):

1993 - 1996
Senior Environmental Scientist
Environmental Department
Hawaiian Electric Company, Inc.

1991 - 1993
Staff Environmental Engineer
Acurex Environmental Corporation
Mountain View, California

1989 - 1991
English Instructor
Sichuan University
Sichuan, China

1988 - 1989
Mechanical Engineer
Westinghouse Electric Corporation
Sunnyvale, California

HELCO RT-15B
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
JAMES C. CLARY, Jr.

PRESIDENT
JIM CLARY & ASSOCIATES, INC.

Subject: Keahole CT-4/5 Air Permitting Issues

INTRODUCTION

Q. Would you please state your name and address for the record?

A. James C. Clary, Jr., 12700 Hillcrest Rd., Suite 210, Dallas, TX 75230

Q. What is your profession?

A. I am a consulting meteorologist.

Q. Are you a certified consulting meteorologist?

A. Yes, by the American Meteorological Society (Certified Consulting Meteorologist No. 320).

Q. Where are you employed?

A. I am President and owner of Jim Clary & Associates.

Q. Please describe your duties and responsibilities at Jim Clary & Associates.

A. I provide consulting services and training in air quality. The consulting services include dispersion modeling and air-related issues associated with the preparation of air permit applications.

Q. How long have you been in your current position?

A. About twenty-two (22) years.

Q. Please describe your educational background.

A. I have a Bachelor of Science degree in meteorology, and a Masters of Science in meteorology, both from Florida State University.

Q. Please describe your training and experience as a consulting meteorologist.

A. Since 1973, I have served as a consultant to many industrial clients, and have managed or served as senior investigator on over two hundred (200) projects, including prevention of significant deterioration ("PSD") permits, State Implementation Plans ("SIP") revisions, Boilers and Industrial Furnaces ("BIF") permits, Title V permits and toxic gas release evaluations.

Q. Do you specialize in any particular area of meteorology?

A. Yes. I specialize in air quality. I perform dispersion modeling to determine the effects of potential air emissions on ambient air quality, and to determine whether potential air emission impacts would comply with federal and state air quality standards.

Q. Do you have a copy of your current curriculum vitae?

A. Yes. See HELCO-R-15B00.

Q. Please describe some of the projects in which you have been involved as a consulting meteorologist.

A. See HELCO-R-15B01.

Q. Have you previously qualified and testified as an expert witness in the field of meteorology?

A. Yes. I've prepared depositions, testimony, or affidavits in at least twelve (12) cases.

Q. What is the scope of your testimony?

A. I will provide testimony that, contrary to what is alleged in the Keahole Defense Coalition's Position Statement ("KDC Position Statement") in this docket, HELCO took prudent and diligent actions to obtain the final Prevention of Significant Deterioration ("PSD") air permit for Keahole units CT-4 and CT-5, and that the significant delays encountered in obtaining the air permit were not predictable and were beyond HELCO's reasonable control.

KEAHOLE STATION PROJECT

Q. Mr. Clary, are you familiar with the proposed Keahole Station project in North Kona, Hawaii?

A. Yes. I first became involved with the Keahole Station Project in the summer of 1992.

Q. Are air emissions governed by law in the State of Hawaii?

A. Yes, they are governed by the federal Clean Air Act, the State of Hawaii's Air Pollution Control Law and the regulations implementing both statutes.

Q. Please describe how you begin the air permitting process in Hawaii.

A. The process begins with discussing the project with the State of Hawaii Department of Health ("DOH") air permitting staff. These discussions are used to define the procedures that will be used in the permit application. The next step is the submittal of the air permit application to the DOH. A copy of the permit application is also sent to the Environmental Protection Agency ("EPA") Region 9 in San Francisco. When the DOH receives an application, it performs a completeness review and will advise the applicant when they find that the application is "complete".

Q. What does "complete" mean in the permitting process?

A. "Complete" as defined in the current Hawaii Administrative Rules ("HAR") on air permitting "means, in reference to an application for a permit, that the application contains all of the information necessary to begin and reasonably complete processing the application." (See §11-60.1-1 of the HAR.) The completeness determination is an important step in the air permitting process because it means that the applicant has provided all of the information that it is required to provide.

Q. What happens after the completeness determination?

A. The DOH *thoroughly reviews the application and independently verifies the* calculations. The DOH then prepares a draft permit and an air quality summary. The air quality summary contains the DOH's opinions and findings concerning the impact of the proposed project on air quality. It is my understanding that DOH sends the draft permit and air quality summary to the EPA Region 9 in San Francisco for their informal review.

Q. What happens to the DOH draft permit and air quality summary after EPA's informal review?

A. After receipt of EPA's informal approval, the DOH issues a public notice and provides an opportunity for the public to comment on the draft permit and air quality summary. The public may submit both oral and written comments at the public hearing. The public may also submit written comments to the DOH at any time during the public comment period.

Q. What happens after the public comment period?

A. The DOH reviews all written and oral comments. The DOH also prepares a written summary of comments received and a response to those comments. If the DOH determines that additional information is needed, another public comment period and hearing will be held to allow the public the opportunity to comment on the new information.

Q. Please describe what happens when the DOH is satisfied that it has responded to all comments and does not require any additional information.

A. The DOH prepares a final permitting package consisting of the response to comments and a final air permit. This permitting package is sent to the EPA Region 9 in San Francisco for their formal approval and signature. Once the DOH receives the signed copy of the permitting package from the EPA, they also sign the permitting package and send copies to the applicant as well as the members of the public who submitted comments.

Q. Is the final permit effective at this point?

A. Yes, unless an appeal is filed with the Environmental Appeals Board in Washington, D.C.

Q. Could you please summarize the role of the DOH and the EPA in the permitting process?

A. Once the application is found to be complete, the DOH takes the lead role. The DOH prepares the draft permit, the Ambient Air Quality Impact Report and any supplements when additional information is considered. DOH also prepares the formal response to comments raised in the public comment period. Before beginning the public comment period, the DOH consults with the EPA Region 9 in San Francisco to get a preliminary indication of EPA's concurrence with the draft permit and Ambient Air Quality Impact Report. After the close of the public comment period EPA reviews DOH's response to the public comments. EPA must also sign the final air permit DOH has prepared before the permit can be issued.

CHANGES IN THE AIR QUALITY REGULATIONS

Q. When did HELCO submit the first air permit application for CT-4 and CT-5?

A. January 13, 1993.

Q. Did DOH find this application to be complete?

A. Yes, on June 14, 1993.

Q. Did DOH make changes to the air permitting rules after finding this application to be complete?

A. Yes, on November 26, 1993, DOH adopted new rules for Air Pollution Control found at HAR Title 11, Chapter 60.1. These rules govern covered source permitting. DOH adopted these rules in order to satisfy Title V of the 1990 Clean

Air Act Amendments, which requires an Operating Permit Program, and the 1992 amendments to Hawaii's Air Pollution Control Law, which are codified in Chapter 342B of the Hawaii Revised Statutes.

Q. What did HELCO do to address the changes in air regulations?

A. On February 1, 1994, HELCO submitted the Covered Source Permit application for CT-4 and CT-5.

Q. Did DOH find this additional application to be complete?

A. Yes, on May 13, 1994, DOH deemed the application complete.

FIRST PUBLIC HEARING AND DRAFT PERMIT (SEPTEMBER 1994)

Q. What happened after DOH found that the application was complete?

A. DOH prepared the draft permit and the Ambient Air Quality Impact Report for this project. The Ambient Air Quality Impact Report summarizes the project and emissions, the BACT analysis, and the Air Quality Analysis. The Air Quality Analysis contains dispersion modeling demonstrating the project will not cause or contribute to an exceedance of any Prevention of Significant Deterioration ("PSD") Increment and any State Ambient Air Quality Standard ("SAAQS").

Q. Did EPA review DOH's draft Ambient Air Quality Impact Report?

A. Yes, it is my understanding that the draft permit and draft Ambient Air Quality Impact Report were sent to EPA for informal review before the public comment period.

Q. Did DOH then publish its draft permit and Ambient Air Quality Impact report for public review and comment?

A. Yes, on August 12, 1994 DOH published a public notice, and on September 12, 1994, a public hearing was held. HELCO's application, all data submitted by

HELCO, DOH's Ambient Air Quality Impact Report, and the draft permit were available for public inspection, and comments were received through September 15, 1994.

DOH announced during the first public hearing that a second public hearing would be held to afford an opportunity for the public to review additional modeling based on new on-site stack top (32-m) meteorological data that had not been available when the application was submitted.

Q. Did DOH receive comments regarding air quality monitoring data?

A. Yes, DOH provided HELCO a summary of comments received during the first public comment period on December 28, 1994. According to DOH, only one comment was received related to the ambient air quality monitoring data: "A commenter wanted to know whether the Department and USEPA intend to require HELCO to measure ozone levels at Keahole and calculate future levels before granting final approval of the permit."

This comment had been submitted by Keichi Ikeda, and a review of his comments shows that he was only questioning the use of the Waiakea ozone concentration in the calculation of the ambient NO_2 impact using the ozone limiting method. Mr. Ikeda did not raise any concerns with the background data DOH used in the Ambient Air Quality Impact Report. Mr. Ikeda did request that DOH require HELCO to update its application with the new 32-m (105-ft) meteorological data as DOH had indicated it would at the public hearing.

Q. Does this differ from KDC's current position that "the Company hastily assembled data to support its air permit application, which action only invited criticism and, more importantly, appeals from the Company's air permit" (KDC Position Statement, page 10)?

A. Yes. As I described earlier, Mr. Ikeda's September 12, 1994 comments did not question the background air quality data and requested that DOH require HELCO to update its application with the new 32-m (105-ft) meteorological data.

32-METER METEOROLOGICAL DATA AND THE SECOND PUBLIC HEARING AND DRAFT PERMIT (APRIL 1995)

Q. Why didn't HELCO use the 32-m meteorological data in the earlier permit application?

A. The 32-m meteorological data collection was not completed until March 1, 1994, approximately one year after the application was submitted. On September 8, 1994, prior to the first public comment period, HELCO submitted additional modeling using the 32-m data in connection with its application for an air permit for CT-2.

Q. What did DOH do with the new data?

A. DOH reviewed the data and prepared "Supplement A" to its Ambient Air Quality Impact Report. In Supplement A, Section I, DOH explained the purpose of its supplement:

> "This Supplement to the Ambient Air Quality Impact Report only addresses the ambient air quality impact assessment as it relates to PSD/Covered Source Permit Application No. 0007-01-C for the proposed construction and operation of CT-4 and CT-5. Supplement A does not supersede any section or portion of the Ambient Air Quality Impact Report dated August 4, 1994, but rather supplements this report."

Q. Did EPA review DOH's draft Ambient Air Quality Impact Report as supplemented with Supplement A?

A. Yes, it is my understanding the draft permit and draft Ambient Air Quality Impact Report with Supplement A were sent to EPA for informal review before the official public comment period.

Q. Did the public have an opportunity to review Supplement A?

A. Yes. On March 9, 1995, DOH published a public notice announcing the opportunity to comment on the application, all data submitted by HELCO, the Ambient Air Quality Impact Report, including Supplement A, and the draft permit. A public hearing was held on April 10, 1995.

Q. Were there any comments on the Ambient Air Quality monitoring data?

A. Yes, DOH provided HELCO a summary of comments received during the second public comment period on June 9, 1995. According to DOH, the only comments received related to the Ambient Air Quality Monitoring data were as follows:

- "Several commenters questioned the acceptability of the background data used in the air quality analyses. One commenter cited from guidance that background air quality data must be representative and not more than three years old. Another commenter identified two documents which suggested an ambient air monitoring program be conducted in Kona."
- "One commenter (a) indicated that the 1984-85 SO_2 data contains numerous missing hourly concentration values, and (b) requested a copy of the 1984-85 NO_X data and a written discussion of the quality control procedures."

Q. Did DOH agree with these comments and require additional data?

A. No. Responding to these comments, the DOH determined that the ambient air quality monitoring data satisfied the permitting requirements. DOH did not ask

HELCO to collect any new ambient air quality data. On September 28, 1995, DOH sent its response to comments and its proposed final permit to EPA for signature.

Q. Did EPA agree with the public comments and require additional data?

A. No. The EPA letter dated November 14, 1995, only objected to DOH's NO_X BACT determination. In the letter EPA states: "In order for EPA to sign the final permit, HDOH must amend PSD/CSP No. 0007-01-C to require, at the minimum, the application of SCR during combined cycle operation of CT Units 4 and 5." There were no comments concerning the ambient air quality data.

NO_X NETTING AND THIRD PUBLIC HEARING AND DRAFT PERMIT

Q. In Mr. Seu's testimony in HELCO RT-15A, he addresses the EPA change in position with respect to Best Available Control Technology ("BACT") and HELCO's decision to net out of BACT for NO_X. What changes, if any, did DOH make to the draft permit and Ambient Air Quality Impact Report based on the additional information submitted by HELCO in response to EPA's change in position?

A. DOH added the equipment shutdown permit conditions required by the netting for NO_X BACT. DOH updated its Ambient Air Quality Impact Report by adding Supplement B. In Supplement B, Section I, DOH explains the purpose of this supplement:

> "This supplement will further discuss the Best Available Control Technology (BACT) for sulfur dioxide (SO_2) and nitrogen oxides (NO_X). The first part of this supplement examines the additional information submitted to the Department of Health (DOH) by Hawaii Electric Light Company, Inc. (HELCO) regarding naphtha fuel. The second part addresses the permit application revision [in] which HELCO uses a United States

> Environmental Protection Agency (EPA) emissions netting method to determine the net NO_X emissions increase from the proposed project."

DOH did not revise the dispersion modeling and background ambient air quality data contained in its initial Ambient Air Quality Impact Report and Supplement A following EPA's change in position on NO_X.

Q. Did the public have an opportunity to comment on Supplement B?

A. Yes, the DOH held a third public comment period as described in Mr. Seu's testimony.

Q. Were there any additional comments regarding the air quality modeling and ambient air quality data raised in the third public comment period?

A. No new comments were received, and DOH did not revise the dispersion modeling and background ambient air quality data contained in initial Ambient Air Quality Impact Report and Supplement A. DOH again sent a proposed final PSD air permit to EPA for their approval. On October 15, 1997, the EPA approved the final PSD air permit and DOH issued the final permit to HELCO by letter dated October 28, 1997.

FILING OF PETITIONS AGAINST PERMIT TO EPA ENVIRONMENTAL APPEALS BOARD

Q. What happened after the issuance of the final air permit?

A. In November and early December 1997, nine petitions were filed against the Keahole permit to the EPA's Environmental Appeals Board ("EAB"), including a petition by KDC.

Q. What did the EAB decide?

A. On November 25, 1998, the EAB issued an Order Denying Review in Part and Remanding in Part. 8 E.A.D. 66 ("1998 EAB Order"). The EAB denied appeals of the permit that were based on challenges to: (1) DOH's use of a netting analysis with respect to NO_X emissions, (2) DOH's determination of BACT, and (3) certain aspects of DOH's ambient air and source impact analysis. However, the EAB remanded the permit and directed DOH to reopen the permit proceedings for the limited purposes of (1) providing an updated air quality impact report incorporating current SO_2 and PM data and (2) providing a sufficient explanation of why CO and O_3 data are reasonably representative or to perform a new air quality analysis based on either on-site data or other data shown to be representative of the air quality in the area affected by the Project. 1998 EAB Order at 109.

Q. Did the EAB suggest in its order that "the Company hastily assembled data to support its air permit application" as KDC now contends (KDC Position Statement, page 10)?

A. No. The EAB found that that: (1) DOH's response to the public's comments regarding the currentness for the SO_2 and particulate matter data were not adequate (1998 EAB Order at 101), and (2) DOH had not provided an adequate response to comments explaining why the CO and O_3 data were representative (1998 EAB Order at 104).

Q. What actions did HELCO take to respond to the EAB remand?

A. HELCO initiated discussions with DOH in early December 1998 to review the 1998 EAB Order. I worked very closely with DOH staff in December 1998 to identify acceptable air quality data to use in responding to the EAB remand. Based on these discussions and a careful evaluation of all options, HELCO proposed to DOH the use of five months of data from HELCO's Huehue Substation (ozone), and State air monitoring stations at the Keahole airport

(PM_{10}), Konawaena (SO_2), and Kapolei (CO). HELCO began collecting air quality data at Huehue in January 1999.

Q. What factors were important in arriving at the selection of this option?

A. The 1998 EAB Order made another public comment period mandatory. Therefore, using the State air monitoring stations at the Keahole airport (PM_{10}), Konawaena (SO_2), and Kapolei (CO) would not result in any significant additional delays. Using the Huehue ozone data would also not result in any significant delays, as five and one-half months of data was sufficient (see HECO letter to EPA dated July 6, 1999).

Q. Did DOH approve HELCO's proposal?

A. Yes. DOH approved the use of data from HELCO's Huehue Substation (ozone), and State air monitoring stations at the Keahole airport (PM_{10}), Konawaena (SO_2), and Kapolei (CO) in Supplement C to its Ambient Air Quality Impact Report in August 1999.

FOURTH PUBLIC HEARING AND DRAFT PERMIT (OCTOBER 1999)

Q. What was the purpose of the fourth public hearing?

A. The purpose was to allow the public the opportunity to review the results of the five months of data from HELCO's Huehue Substation (ozone), and State air monitoring stations at the Keahole airport (PM_{10}), Konawaena (SO_2), and Kapolei (CO) described in DOH's Supplement C to its Ambient Air Quality Impact Report issued in August 1999. DOH issued a public notice on August 26, 1999 and held a public hearing on October 7, 1999.

Q. What happened after the close of the fourth public comment period?

A. In a letter dated December 9, 1999 to DOH, EPA took the position that a full 12 months of monitoring data for SO_2, CO, O_3 and PM_{10} at the Huehue monitoring station should be collected. Also, EPA recommended that a second station measuring SO_2 and PM_{10} be installed to determine the representativeness of the Huehue data. This was not expected, as it was my understanding that EPA had reviewed DOH's Supplement C before the third public comment period. By letter dated January 5, 2000, DOH concurred with EPA's position and required that HELCO collect additional air quality data.

Q. What actions were taken by HELCO to respond to this determination by EPA and DOH?

A. HELCO directed me to immediately begin working with DOH to obtain their approval of a second "confirmatory" air quality monitoring site for SO_2 and PM_{10}. HELCO was able to obtain approval and installed an additional air quality monitoring site at the end of Kakahiaka Street in the Kona Palisades area. DOH formally approved this site in a letter dated March 1, 2000. HELCO collected two months of air quality monitoring data at this site, in accordance with the EPA and DOH directives.

Q. What happened after HELCO submitted the additional data?

A. After HELCO submitted all required Huehue air quality data, DOH prepared Supplement D of its Ambient Air Quality Impact Report on December 27, 2000. This supplement addressed the Huehue and Kakahiaka Street air quality data. DOH also prepared responses to the comments received at the fourth public hearing. DOH then issued a public notice on January 30, 2001 and held a public hearing on March 6, 2001.

FIFTH PUBLIC HEARING AND DRAFT PERMIT (MARCH 2001)

Q. What was the purpose of the fifth public hearing held on March 6, 2001?

A. The purpose was to allow the public the opportunity to review DOH's Supplement D and the response to the fourth public comment period comments.

Q. What happened after the close of the fifth public comment period?

A. After responding to comments, DOH sent a proposed final air permit to EPA for their approval. On July 18, 2001, the EPA approved the final air permit and DOH issued the final permit to HELCO by letter dated July 25, 2001.

FINAL PERMIT AND APPEALS

Q. What happened following the issuance of the final air permit on July 25, 2001?

A. In August 2001, six petitions for review were filed with the EAB.

Q. What issues were raised in these petitions?

A. The Petitioners, including KDC, raised a number of objections. These included:

- objections to the ambient air quality data that HELCO collected for use in the revised Ambient Air Quality Impact Report based principally on the location of the monitoring station;
- challenges to DOH's use of the data collected for a confirmatory study;
- allegations that some data used in the Ambient Air Quality Impact Report were not current; and
- challenges that DOH improperly limited the scope of the public comment on remand.

Q. What was the EAB's determination on these petitions?

A. On November 27, 2001, the EAB issued its order denying review of all petitions. 10 E.A.D. 219 ("2001 EAB Order"). The EAB found that the Petitioners failed to identify clear error or any other reason for the EAB to grant review. The EAB found that DOH required HELCO to gather new ambient air quality data, and the record adequately supported the location chosen to collect these data. (2001 EAB Order, page 219.) The EAB found no legal authority barring the confirmatory study. Moreover, while nothing in the regulations prohibited DOH from requiring such a study, the confirmatory study itself was not governed by the regulatory requirements for preconstruction monitoring, nor were the data from the confirmatory study used in the air quality analysis. The EAB found no fault with the data collected and held that the data did qualify as "current" data. Finally, the Petitioners' argument that DOH improperly limited the scope of public comment was rendered moot by DOH's subsequent notice for public comment, which requested comments on the entire draft permit and the Ambient Air Quality Impact Report. (2001 EAB Order, pages 219-220.)

CONCLUSION

Q. How would you summarize the impact of the issues raised by the commenters, including KDC, concerning ambient air quality data?

A. As is shown in HELCO-R-15B02, the compliance evaluation did not change significantly as a result of the new data. The purpose of the Ambient Air Quality Impact Report is to evaluate whether the project will cause an exceedance of the air quality standards. In other words, the emissions cannot be more than 100% of these air standards. As the chart shows, air quality impacts did not change significantly with the consideration of additional data. Most importantly, at no time did the air quality impacts of this project approach the air standards.

Q. Could you also address the impact, if any, of the additional monitoring data on the final air permit?

A. The additional monitoring data did not result in any changes to the final air permit.

Q. Does this conclude your testimony?

A. Yes, it does.

James C. Clary, Jr.

SUMMARY

Air quality expert with 33 years of consulting experience. Managed or served as senior consultant on over 200 projects. Areas of expertise: 1990 Clean Air Act regulations, permitting, and dispersion modeling studies.

EDUCATION

May 1974 **Florida State University;** Tallahassee, FL
Master of Science, Meteorology

May 1971 **Florida State University;** Tallahassee, FL
Bachelor of Science – Major in Meteorology

EXPERIENCE

1984 – Present **JCA;** Dallas, Texas – **President**

- Supervised a staff of professionals addressing air permitting regulatory compliance and dispersion modeling studies.
- Managed projects including Title V permit applications, PSD applications, health-effects studies, BIF applications, state permit applications, and BART eligibility studies.
- Developed air dispersion modeling training courses for clients in the private and public sectors.
- Developed and received EPA approval for a simple/complex terrain dispersion model.
- Designed personal computer software for permit tracking.
- Wrote a FORTRAN program used in the assessment of releases of toxic gasses into the atmosphere.
- Modified the data entry systems, run systems, on-line help systems, and user's guides for several of the U.S. Environmental Protection Agency's air dispersion models
- Provided expert witness testimony at permit hearings.

1979 – 1984 **Trinity Consultants;** Dallas, Texas – **Vice President**

- Served as project manager on over 30 air quality projects.
- Developed numerous computer programs to meet the needs of different projects.
- Lead projects relating to air quality issues including routine emissions and toxic gas releases.
- Served as lead consultant for a field study of VOC emissions from the waste water treatment system of a chemical plant in Louisiana.

1974 – 1979 **Dames & Moore;** Atlanta, Georgia – **Consulting Meteorologist**

- Completed studies of both routine and accidental emissions from nuclear power plants.
- Developed numerous computer programs used to reduce and process meteorological data from several nuclear power plants.
- Created a data gathering and verification system for the meteorological system at a nuclear power plant.

CERTIFICATIONS

- Certified Consulting Meteorologist (CCM).
- CCM is a technical distinction awarded by the American Meteorological society.
- Certification is based upon knowledge, experience, and character. Certification requires both written and oral examinations.

PROFESSIONAL ORGANIZATIONS

- American Meteorological Society
- Air & Waste Management Association. Served as Chapter Chairman and Technical Session Chairman.
- Gerson Lehrman Group Industrial Council

INSTRUCTION

- Taught numerous courses on dispersion modeling (including dispersion modeling laboratories), air permitting, reporting, and regulations.
- Served as an instructor for an EPA-sponsored dispersion modeling course.

SELECTED PUBLICATIONS

- James Clary, Stephen Beene, and Gabriel Rothman, "Depiction of CALPUFF Regional Haze with MM5 Output versus National Weather Service Data," Paper Presented, Guideline on Air Quality Models: Applications and FLAG Developments – An A&WMA Specialty Conference (April 2006), Denver, CO.
- James Clary, Stephen Beene, and Gabriel Rothman, "Examination of Differences in 24-hour Average AERMOD and ISCST3 Concentrations," Paper Presented, A&WMA's 99th Annual Conference & Exhibition (June 2006), New Orleans, LA.
- James Clary, Stephen Beene, and Gabriel Rothman, "Evaluation of CALPUFF Light as a Screening Tool," Paper Presented, Electric Utilities Environmental Conference 2007 (January 2007), Tucson, AZ.

James C. Clary, Jr.
Project Experience

Title V Permit Applications, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of 30 applications for Hawaiian Electric Company, Maui Electric Company, and Hawaii Electric Light Company.

Minor Source Permit Applications, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of over 50 minor source applications.

PSD Permit Applications for Major Sources, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of 7 permit applications.

Complex Terrain Modeling, Hawaiian Electric Company, Inc., Honolulu Hawaii
Conducted a complex terrain modeling study for a revision to a PSD permit. Negotiated with the EPA on matters of modeling procedures, meteorological data, and monitor locations.

Annual Emission Inventories and Annual Compliance Certifications, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of 9 annual emission inventories and 9 annual compliance certifications.

Air Quality Analyses Including Regional Haze Modeling, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of multiple analyses for 4 electrical generation facilities.

Multi-Pathway Risk Assessments, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Supervised the preparation of multiple assessments to evaluate the impact of hazardous air pollutants from several electrical generation facilities.

Health Risk Studies, Hawaiian Electric Company, Inc., Honolulu, Hawaii
Served as project manager for a project evaluating the health-risk impact of emissions from 4 electrical generating plants.

Expert Witness Testimony, Confidential Client, Oklahoma City, Oklahoma
Testified before a jury in a case involving the impact of emissions from a natural gas processing plant.

Expert Witness Testimony, Confidential Client, Houston, Texas
Prepared studies submitted as expert testimony in a case involving a superfund site.

Expert Witness Testimony, Confidential Client, Austin, Texas
Testified before a judge in a case involving a cement plant where the client was challenging state air regulations.

Expert Witness Testimony, Confidential Client
Testified multiple times before state land use commissions regarding the modeled impact of a proposed power plant facility.

Expert Witness Testimony, Confidential Client, Eunice, Louisiana
Testified before a judge in a case involving a large train derailment that released hazardous materials.

Expert Witness Testimony, Confidential Client, Baton Rouge, Louisiana
Testified before a judge involving an accidental ammonia release at a manufacturing facility.

James C. Clary, Jr.
Project Experience (Continued)

Expert Witness Testimony, Confidential Client, New Iberia, Louisiana
Testified before a judge in a case involving a large train derailment that released xylene.

Expert Witness Testimony, Confidential Client, Opelousas, Louisiana
Testified before a judge regarding the past air quality impact of a manufacturing facility.

Data Acquisition and Modeling System, Southern California Edison, San Diego, California
Developed the data acquisition and modeling system for the San Onfre Nuclear Generating Station. Components included data verification quality assurance and instrument calibration. Conducted the dispersion modeling in support of the required construction permits.

Plume Visibility Study, Confidential Client, Trona, California
Conducted a dispersion modeling study for an industrial plant. The local air board directed the client to develop a plan to eliminate an opacity problem that occurred under certain meteorological conditions. The model development and results were accepted by the local air board.

Air Dispersion Model Development
Developed an air dispersion model addressing simple and complex terrain. The model was accepted by the EPA and is currently used by public companies and regulatory agencies throughout the U.S.

Title V Permit Application, Kerr-McGee Chemical Company, Hamilton, Mississippi
Supervised the preparation of a Title V permit application which included a titanium dioxide pigment operation, a manganese production operation, and a chlorate production operation. Application included a detailed emission inventory which quantified or described emissions from all potentially significant emission points.

Title V Permit Application, Kerr-McGee Chemical Company, Mobile Alabama
Supervised the preparation of a Title V permit application for a production facility. Application included a detailed emission inventory and a review of all applicable state and federal regulations.

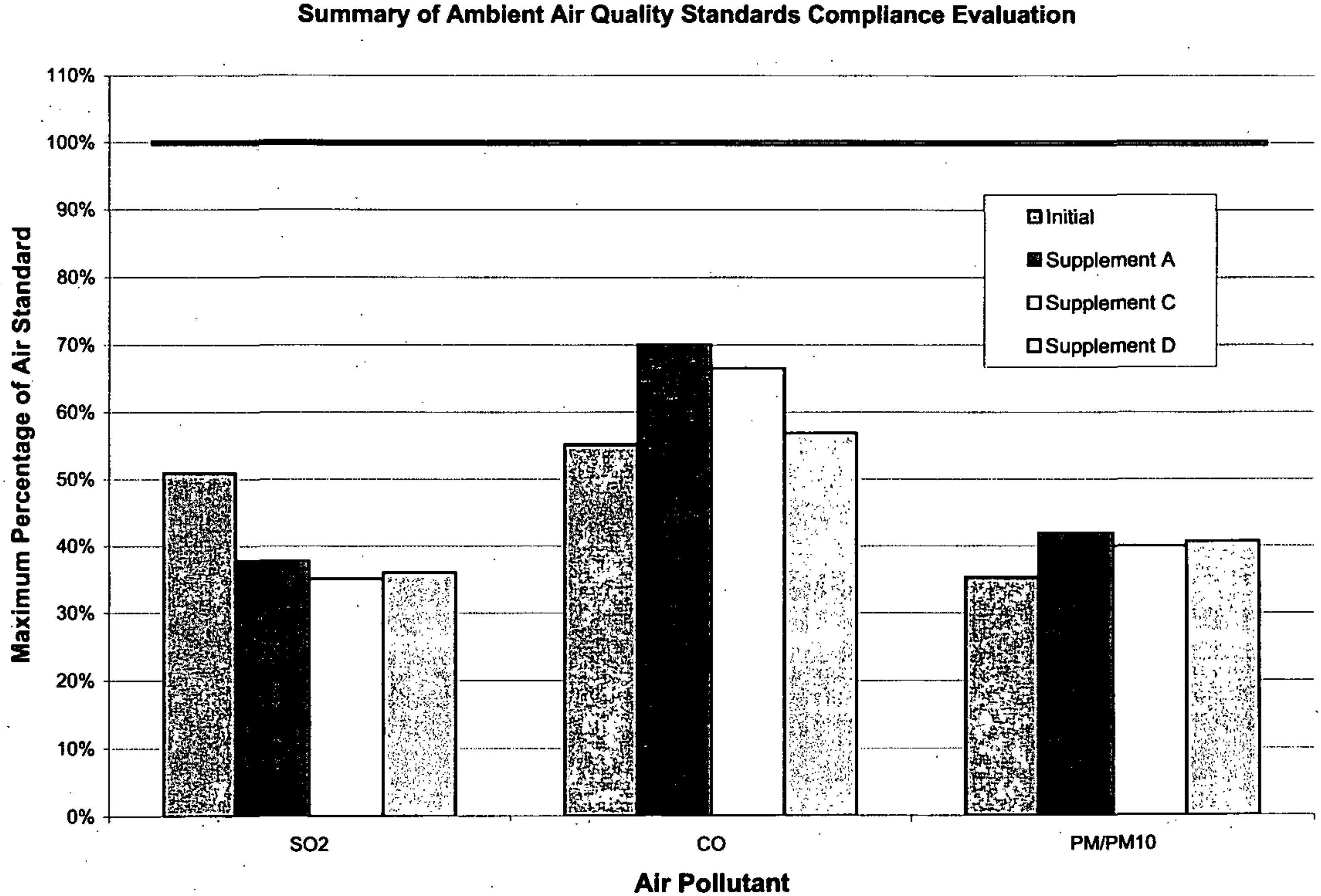
Regulatory Requirements for Burning Used Oil, TXU Business Services, Dallas, Texas
Determined proper regulatory requirements for burning used oil.

Title V Permit Application and Minor Permit Modifications and Applications, Nevada Cement Company, Fernley, Nevada
Supervised preparation of the permit and several minor permit modifications and applications which included emission inventories and review of all applicable regulatory requirements.

Title V Permit Application, Upham Oil & Gas Company, Mineral Wells, Texas
Supervised preparation of the application for the Chico Gas Plant for submittal to the Texas Natural Resources and Conservation Commission.

Modeling to Support Permitting Activities, Owens-Brockway, Waco, Texas
Supervised modeling to support permitting activities for glass container manufacturing plants.

Permit-by-Rule Documentation, Perlos, Inc., Fort Worth, Texas
Prepared documentation for surface coating and stripping facility for submittal to the Texas Natural Resources and Conservation Commission. Documentation included emission calculations of surface coating operations.



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REBUTTAL TESTIMONY OF
BARRY M. NAKAMOTO

PRINCIPAL
ENVIRONMENTAL DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: 1) Pre-PSD Construction,
2) Noise Issues and Permitting, and
3) On-site water source.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barry Nakamoto. My business address is P.O. Box 2750, Honolulu, Hawaii, 96840. My resume is attached as HELCO- R-15C00.

Q. What is your present position at Hawaiian Electric Company?

A. I am the Principal of the Air and Noise Division in the Environmental Department. I also served as the Project Manager for the Keahole Projects from about 1992 through 2000.

Q. What areas will be covered in your testimony?

A. My testimony is provided in rebuttal to the Keahole Defense Coalition's (KDC) statements regarding:

1) Pre-PSD construction;

2) Noise issues and permitting; and

3) On-site water source.

PRE-PSD CONSTRUCTION

Q. What was your involvement in the Pre-PSD construction for this project?

A. I was the Project Manager during this period of the project.

Q. What does the term "Pre-PSD construction" mean?

A. "Pre-PSD construction" refers to construction activities that are authorized to be done before the effective date of a Prevention of Significant Deterioration ("PSD") permit. Pre-PSD construction activities are those that serve as improvements to the existing power plant operations and are not directly or solely associated with the emissions unit being permitted.

Q. Please identify the Pre-PSD facilities that were constructed at Keahole.

A. The Pre-PSD common facilities are the Warehouse/Shop building (completed in December 1998), the upgrades to the plant fire protection system (completed in September 1999), and the water treatment system upgrades for Keahole CT-2 (completed in December 1999).

Q. KDC characterizes the Pre-PSD construction at Keahole as a "scheme devised by HELCO" at substantial expense (KDC Position Statement, pages 11 and 21). Is this an accurate characterization?

A. No. The rules of the Environmental Protection Agency ("EPA") permit Pre-PSD construction. EPA has defined "begin actual construction" in its rules at 40 C.F.R. Section 52.21(b)(11): "*Begin actual construction* means, in general, initiation of physical on-site construction activities on an emissions unit which are of a permanent nature. Such activities include, but are not limited to, installation of building supports and foundations, laying of underground pipe work and construction of permanent storage structures." In addition to its rules, EPA has guidance documents that explain what construction can begin before the issuance of a PSD permit. HELCO followed this guidance in requesting regulatory approval of its Pre-PSD construction. In granting the Company's request, EPA and DOH agreed that "the proposed construction activities will serve as improvements to the existing power plant and are not directly or solely associated with the proposed emissions units."

Q. Has Pre-PSD construction been successfully utilized on other HELCO and Maui Electric Company ("MECO") projects?

A. Yes. As explained in HELCO's response to CA-IR-504, the Pre-PSD work contemplated by HELCO was the same type of Pre-PSD work that was performed by HELCO and MECO on earlier generating units under previous DOH and EPA approvals. Warehouse facilities and water treatment upgrades were installed as allowable Pre-PSD construction in conjunction with HELCO's CT-3 project and MECO's Maalaea DTCC No. 1 and M17 projects. Fire protection upgrades were also allowed as Pre-PSD work in conjunction with HELCO's CT-3 project and MECO's Maalaea DTCC No. 1 project.

Q. Have HELCO's customers benefited in the past from Pre-PSD construction?

A. Yes. The most notable example is that by doing Pre-PSD work for CT-3, HELCO was able to install CT-3 and have it operational in July 1992, which averted the need for further rolling blackouts on HELCO's system.

Q. Is Pre-PSD construction a recognized practice to minimize construction time after receipt of an air permit?

A. Yes. This is a common practice nationally and has been permissibly utilized in the past by HELCO and MECO. Commencing Pre-PSD work was part of HELCO's strategy to install new generation as quickly as possible. Given the urgency of the need for CT-4 and CT-5, HELCO commenced Pre-PSD work when it experienced delays in obtaining the PSD permit for CT-4 and CT-5. Doing Pre-PSD shortened the time required to install CT-4 and CT-5 once the PSD permit was received.

Q. How did HELCO's use of Pre-PSD construction for CT-4 and CT-5 benefit the Keahole Plant?

A. All three of the Pre-PSD common facilities were placed into service and were used and useful, and were providing benefit to the existing plant operations, well in advance of the receipt of the PSD permit. The shop/warehouse building was completed in December 1998, the upgrades to the fire protection system were completed in September 1999, and the upgrades to the water treatment system were completed in December 1999. (The PSD permit became final in November 2001.)

By completing Pre-PSD construction in 1999, HELCO's customers received the benefits of more reliable operations from the Keahole Plant approximately five years sooner than if HELCO had not performed Pre-PSD construction. The completion of the Pre-PSD work also reduced the amount of Post-PSD construction required by approximately 6 months.

Q. KDC claims HELCO's consultant offered no assurance that Pre-PSD construction would work. (KDC Position Statement, page 21.) Is that correct?

A. No. KDC mischaracterizes the statements of HELCO's construction management consultant. The description of proposed Pre-PSD work was provided by HELCO's Construction Management consultant, Mr. Loris McDaniel of Stone & Webster Engineering and was provided to the Commission as HELCO-R-500B in Docket No. 7623. In the work description, Mr. McDaniel states: "Construction of common facilities has been allowed by the regulatory agencies on some projects, however, we are not in a position to determine or offer counsel as to what specific items the State of Hawaii agencies may allow." Mr. McDaniel makes this statement as his expertise is in construction management and defers to others for interpreting regulations related to Pre-PSD construction. He was clear on the permissibility of the concept, but deferred to the regulators as to the specific items which they would interpret to qualify as Pre-PSD work for the particular project. Mr. McDaniel made the same disclaimer when he described the Pre-PSD work items for HELCO's CT-3 project and the Maalaea M17 project. In all cases, HELCO and MECO requested regulatory approval and awaited signed approval from both the Department of Health ("DOH") and EPA before initiating Pre-PSD construction.

Q. KDC asserts that the strategy of including Pre-PSD work led to "predictable stop work orders" and "predictable delay". What were the "stop work orders" referred to by KDC? (KDC Position Statement, pages 11, 12, and 21.)

A. The orders referred to by KDC were notices and findings of violation ("NOV") received from the DOH on July 27, 1998, and the EPA on September 14, 1998.

Q. What did these NOVs say?

A. The NOVs essentially notified HELCO that the agencies had determined that certain construction activities that HELCO had begun during the Pre-PSD construction phase were not allowed.

Q. Were either of these stop work orders associated with the Pre-PSD construction predictable?

A. No. HELCO relied on written approval from the DOH and EPA before proceeding with Pre-PSD construction. By a letter dated May 31, 1994, HELCO requested approval from the DOH and EPA to proceed with construction of certain Pre-PSD facilities (i.e., the fire protection system upgrades, the shop/warehouse, the water treatment system, and switchyard). HELCO's request was approved by DOH on July 13, 1994 and by EPA on August 17, 1994. Pre-PSD construction was initiated in 1997.

Q. Did the enforcement actions taken by DOH and EPA delay completion of the CT-4 and CT-5 projects?

A. No. While the enforcement actions delayed completion of the Pre-PSD construction, they did not delay the completion of the CT-4 and CT-5 projects. After the NOVs were issued in 1998, DOH and EPA again reviewed the scope of the Pre-PSD construction work requested by HELCO. DOH visited the site to review the work, and both DOH and EPA reviewed detailed engineering drawings for the work. Based on their review, the agencies approved continued Pre-PSD construction with a revised scope of work.

Q. Did the Pre-PSD construction result in "nothing except predictable delays" as KDC claims? (KDC Position Statement, page 12.)

A. No. Quite the contrary. The completion of the Pre-PSD construction allowed the CT-4 and CT-5 projects to be completed sooner than they would have been if the Pre-PSD items had not been completed prior to receipt of the final PSD permit.

NOISE ISSUES

Q. What was your role with regard to criteria for noise utilized in the design of the Keahole CT-4/CT-5/ST-7 projects?

A. As the Project Manager from about 1992 through 2000, I was responsible for coordinating the work of the noise and engineering design consultants for the project.

Q. Who were the consultants that HELCO relied upon for determining the noise criteria and design?

A. HELCO utilized the services of Y. Ebisu & Associates ("Ebisu") for conducting acoustical analyses and determining noise level criteria for the Keahole project. HELCO also utilized Stone & Webster Engineering Corporation ("SWEC") for providing technical assessments of Ebisu's recommendations and incorporating the recommendations into the facility design.

Q. What were the noise standards established for the Keahole Power Plant when the initial plant design was being formulated in the 1992-1993 timeframe?

A. There were no applicable state or county noise regulations in existence on or for the Big Island when the Keahole plant was being designed. As stated by Mr. Al Lono Lyman (in HELCO RT-7 in Docket No. 7048), a condition of the 1987 Amendment to the Conservation District Use Permit ("CDUA") for the Keahole Power Plant established a daytime and nighttime noise level limit of 70 dBA at the Keahole Generating Station's property lines abutting lots with a residence. At that time, the DOH noise rules applied only on Oahu. The CDUA 70 dBA limit was consistent with DOH's maximum permissible sound levels for agricultural lands on Oahu. The 70 dBA limit applicable to agricultural lands was also utilized because of the agricultural park adjacent to the south and west boundaries of the plant.

Q. If there were no DOH noise standards applicable for areas other than Oahu, why did the BLNR impose such conditions on HELCO's CDUAs?

A. During the application process for the prior CDUA approvals (before 1992), concerns regarding noise levels from residents in the agricultural lots abutting the Keahole plant were raised to the Board of Land and Natural Resources ("BLNR"). In response, the BLNR added specific conditions on its CDUA approvals requiring HELCO to comply with a 70 dBA limit for those property lines.

Q. Was the BLNR's limit only applicable during periods of peaking operations (i.e., limited periods when electricity demands were high) as KDC claims? (KDC Position Statement, page 24.)

A. No. The 70 dBA limit imposed by the BLNR as a condition of its approval applied to all periods.

Q. Is HELCO aware if the BLNR consulted the DOH when establishing the condition for 70 dBA at the property lines with residences, as KDC also maintains? (KDC Position Statement, page 24.)

A. HELCO is not aware whether the BLNR consulted with the DOH when establishing these conditions. However, as noted by HELCO's noise consultant, Ebisu, these conditions were consistent with noise limits for agricultural zoned properties in the DOH noise code as it applied to Oahu at that time.

Q. Did the DOH ever confirm the acceptability of this 70 dBA limit for the Keahole plant during this pre-Statewide Noise Rule timeframe (see KDC Position Statement, page 24)?

A. Yes. In June of 1994, the DOH conducted a noise inspection at Keahole in response to a complaint. The DOH report determined:

"The results show that the sound levels from the power plant operations are within the allowable noise levels for Agricultural Zoning Districts, as referenced in Title 11, Administrative Rules, Community Noise Control for Oahu." (See HELCO-R-15C01.)

Q. Did HELCO direct its design engineer, SWEC, to include considerations of potential noise impacts to neighboring properties in the initial design for the new CT-4/CT-5/ST-7 equipment?

A. Yes. The initial design layout prepared by SWEC located the new equipment that emitted higher noise levels on the northeast area of the Keahole property. This was the area furthest away from the agricultural park lots with a residence outside the south and west property boundaries of the plant. In addition, Ebisu and SWEC worked together to use acoustical models to establish specific noise level limits to be incorporated into the specifications for certain equipment which would ensure that the noise levels at the south and west property lines with residences would not exceed 70 dBA. The design utilized the effects of distance by locating the CT-4 and CT-5 equipment in the far northeast portion of the property, and shielding by locating the warehouse along the west edge of the property. The steam turbine building was designed with no ventilation openings on the west face, and liner materials were used within the building walls to attenuate machinery noise. The combustion turbine packages were purchased from Stewart & Stevenson with a 60 dBA at 300 feet performance requirement. Purchase of other support equipment was specified with features to reduce noise levels. These mitigation measures were modeled by HELCO's acoustic consultant, with results in the form of sound level contours showing less than 70 dBA at the agricultural property boundaries. This was consistent with Ebisu's recommendations for the CT-4 and CT-5 installations.

Q. How far are the combustion turbines from the west and south property lines?

A. The CTs are approximately 360 feet from the west property boundary and 560 feet from the south property boundary.

Q. KDC claims that HELCO did not "budget" for noise mitigation costs. (KDC Position Statement, page 23.) Were noise mitigation costs included in the original cost estimates?

A. HELCO did not include a separate line item in its cost estimates for noise mitigation, but the costs for the measures discussed above were incorporated in the original design and procurement of CT-4 & CT-5 and the associated plant equipment.

Q. What noise mitigation was considered with regard to ST-7, which was to be added later?

A. In 1993, Ebisu also provided recommendations for noise mitigation measures to be incorporated for the design of the ST-7 phase of the project. These were provided in HELCO's response to CA-IR-501(f) and were also addressed by Mr. Lyman (HELCO T-6, Docket No. 7623) as follows:

> Following the conversion of CT-4 and CT-5 to a DTCC unit, several noise mitigation measures will be incorporated into the project:
>
> 1) A warehouse with an adjacent sound wall will be located between the air condenser and the western (makai) property to serve as a noise barrier. Together, they should reduce the noise levels by 18 dBA during the P.M. peak period of operation at the existing residence west of the station. This reduction would reduce noise levels at the west residence to 49 Ldn, or 10 Ldn less than existing levels. (Note that HELCO eventually extended the length of the warehouse building to increase available covered storage space instead of building a sound wall.)
>
> 2) The equipment purchased, e.g., heat recovery steam generators, will include specifications specifically designed to reduce noise levels, including attenuation of low- and high- frequency (tonal) sources.
>
> 3) Special design features in the interior finishes and ventilation openings of the Steam Turbine Building will be incorporated to minimize to attenuate noise emissions toward the west and south property boundaries.
>
> 4) Quiet air-cooled condensers, with sound attenuation devices, will be installed. Noise levels will not exceed 55 dBA at 300 feet.
>
> 5) Quiet combustion turbines will be installed. The noise level of each unit will not exceed 60 dBA at 300 feet. Additional mitigation will be achieved by installation of silencers, sound barriers, and walls to reduce the noise levels to 55 dBA at 300 feet.
>
> 6) New equipment procurement specifications will require that low-and high-frequency tonal sources shall be attenuated or masked.
>
> 7) Noise producing activities will be minimized during nighttime hours and early morning hours of probable thermal inversion. When feasible, prior notice of anticipated, but unavoidable, loud noise events will be given to nearby residents.
>
> These mitigation measures will prevent adverse noise impacts of the proposed unit additions by maintaining noise levels at or below existing levels.

Q. Why were the combustion turbines specified at 60 dBA at 300 feet instead of at 55 dBA at 300 feet, which was the recommended specification once ST-7 was added?

A. The combustion turbine packages procured by HELCO were already configured to 60 dBA at 300 feet as part of a negotiated purchase of 5 identical units from Stewart & Stevenson. MECO purchased two units for Maalaea M14 and M16. HELCO purchased three units designated for Puna CT3, and Keahole CT-4 and CT-5. The 60 dBA at 300 feet specified for the combustion turbine generators was sufficient for meeting the noise limits for simple cycle operations in Phases 1 and 2 of the project. For Phase 3, Ebisu recommended the noise levels from the combustion turbines be reduced by an additional 5 dBA to 55 dBA at 300 feet. As explained in HELCO's response to CA-IR-501(c), Stewart & Stevenson accepted the 55 dBA limit for the combustion turbine generators and recommended that the units not be modified immediately, but that the units be sound tested at completion and then adjusted accordingly as necessary with additional sound mitigation measures such as retrofitted silencers, sound barriers, or walls. Stewart & Stevenson's sound level design conservatively met HELCO's specification and their engineers suggested that HELCO wait until the unit was completed as it might already be capable of meeting the 55 dBA requirement with no modifications.

Q. With reference to HELCO's response letter dated June 21, 1993 to Ms. Peggy Ratliff in the EIS, did HELCO state it would obtain buffer zones to mitigate noise from the facility to operate at levels of 70 dBA (See KDC Position Statement, page 13)?

A. No. Additional buffer zones were not necessary for compliance with the noise limits. While HELCO had expressed an interest to the State of Hawaii in additional State land to the north and east of the Keahole property to serve as a buffer zone, there was never any statement made that the buffer zones were necessary to comply with the 70 dBA limits.

Q. Did HELCO's consultant ever recommend that a ½ mile buffer zone be acquired for compliance with the 70 dBA limits (See KDC Position Statement, pages 13-14 and 23)?

A. No. HELCO's noise consultant did not determine that additional buffer zones were necessary. As provided in Mr. Lyman's testimony (HELCO T-6, Docket No. 7623, page 16, lines 10 - 20), "However, to prevent future conflicts due to perception of impacts, HELCO will recommend to the State, which owns the adjacent land, that future land development for residential use adjacent to the station be discouraged; that development of commercial, industrial, or other, less noise sensitive uses be encouraged; and that adequate disclosure of the expected noise levels from the Keahole Generating Station be provided in all real estate transactions and rental or lease agreements involving lands near the station."

Q. Should HELCO have advised its design engineer, SWEC, to include Ebisu's recommendations regarding future development involving the lands near the Keahole station (See KDC Position Statement, page 23)?

A. No, that was not necessary. SWEC's scope of work involved engineering considerations for incorporating design features consistent with the recommendations provided by Ebisu for the Keahole plant and equipment. Ebisu's recommendations regarding property disclosures for future development on the north side had nothing to do with SWEC's scope of work. As indicated by

SWEC's engineer Mr. Robert Christianson during the 1995 contested case hearing, SWEC's focus was on mitigating noise to the south and west sides of the plant.

Q. Why didn't HELCO consider acquiring noise easements from adjoining land owners early in the project, as KDC suggests? (KDC Position Statement, pages 13 and 23.)

A. HELCO did not consider acquiring noise easements first because they were not necessary, and subsequently, obtaining such easements was not practicable. The project was designed, and complied with, the only applicable noise limits contained in the CDUA. Although the former Oahu Noise Rules did not apply to the project, the project was designed to comply with those rules. After the Statewide Noise Rules were adopted in 1996, the project complied with those rules as well. In each of those situations, compliance was determined in accordance with how DOH was interpreting and enforcing the rules at that time. It was not until 1999, well after project design was complete and the equipment had been ordered, that DOH changed its enforcement policy. At that point in time, it was not reasonable to expect that the adjacent land owners, such as DHHL and Agricultural Park tenants (some of whom were active opponents of the project for reasons not limited to noise), would grant or cooperate in the granting of noise easements to HELCO.

Q. Did HELCO's engineering consultant, SWEC, provide comments about how noise limits might be affected if the Oahu Noise Code were applied to the Big Island in the future (See KDC Position Statement, pages 13 and 23)?

A. Yes. In April of 1993, HELCO requested that SWEC provide comments on the acoustical analysis report prepared by Ebisu. In addition to SWEC's comments on the technical feasibility of Ebisu's analysis, SWEC also commented that HELCO might consider using a 45/55 dBA noise limit on the basis that if the DOH's rules regarding "Community Noise Control for Oahu" ("Oahu Noise Rules") was eventually applied to the Big Island, the agricultural lots with residences might be designated "residential" and have a 45/55 dBA limit instead of the 70 dBA limit for agriculture.

Q. Was SWEC correct with respect to the State Noise Code designating the agricultural park as residential?

A. No. SWEC was incorrect. The applicable noise level for agricultural properties with residences under the State Noise Code is 70 dBA, consistent with agricultural properties.

Q. *What instructions did HELCO give its engineers with respect to noise limits?*

A. During the initial design phase of the project, HELCO instructed its design engineers to design a facility to not exceed the 70 dBA limit along the south and west property lines consistent with the recommendations of its noise consultant, Ebisu. HELCO authorized all necessary noise mitigation measures to be incorporated into the plant design to meet these recommendations. HELCO also designed the layout of the facility site to locate the new equipment that emitted higher noise levels on the north east side of the property so as to keep them furthest away from the agricultural park lots with residences on the south and west property boundaries of the plant.

Q. Did HELCO ignore the advice of its consultants with regard to establishing noise level criteria into the facility design as KDC claims? (KDC Position Statement, pages 13 and 23.)

A. No. HELCO followed the advice of its noise consultant, Ebisu, in designing the plant to comply with the 70 dBA limit. HELCO's design engineering consultant also incorporated all of Ebisu's applicable recommendations into the plans for the new plant and equipment.

Q. Did HELCO at any time ever fail to authorize "design or material upgrades for generating units CT-4 and CT-5 at the time of their purchase, or providing for appropriate on-site improvements" as claimed by KDC? (KDC Position Statement, pages 13 and 23.)

A. No. From the initial design phases, HELCO's design engineer incorporated all of Ebisu's recommendations regarding specified noise levels and design features into the engineering plans for the Keahole project.

Q. Could HELCO have avoided extensive noise abatement costs if it had selected a different location, rezoned the property, or purchased noise easements from adjacent property owners early in the process as the Consumer Advocate suggested? (CA Response to HELCO/CA-IR-319.)

A. No. When HELCO designed the project, extensive noise abatement measures were not required. As for selecting a different location, HELCO's urgent need for generation, the availability of the Keahole site or seeking reclassification/rezoning of the Keahole site instead of another CDUA, and the reasons for requesting a CDUA, are addressed by other witnesses (HELCO RT-1 (Lee), RT-4 (Giang), RT-4A (Dizon), and RT-15F (Tsukazaki)). Assuming that HELCO could have successfully reclassified and rezoned the site prior to the settlement agreement, noise limits, such as those currently applicable, could have been imposed as a condition of reclassification/rezoning of the site.

STATE NOISE CODE ISSUED

Q. When did the DOH issue statewide noise rules, and what did those new rules require?

A. The State issued its statewide Community Noise Control rules ("Statewide Noise Rules"), § 11-46 of the Hawaii Administrative Rules ("HAR"), in September 1996. Noise level limits are based on property zoning classifications as summarized below:

Maximum permissible sound levels in dBA.

Zoning Districts:	Daytime (7 a.m. to 10 p.m.):	Nighttime (10 p.m. to 7 a.m.):
Class A	55	45
Class B	60	50
Class C	70	70

Class A zoning districts include all areas equivalent to lands zoned residential, conservation, preservation, public space, open space, or similar type.

Class B zoning districts include all areas equivalent to lands zoned for multi-family dwellings, apartment, business, commercial, hotel, resort, or similar type.

Class C zoning districts include all areas equivalent to lands zoned agriculture, country, industrial, or similar type.

Q. What were the zoning designations at Keahole at the time the plant was being designed?

A. The Keahole power plant and the undeveloped properties to the north and east had a General Conservation state land use and Open Space county zoning. The

Keahole Agriculture Park to the south and east are zoned Agriculture for state land use and county zoning, and residents live in farm dwellings on these properties

Q. How did HELCO interpret the applicability of these new Statewide Noise Rules to the Keahole Project?

A. Upon initial review, there was some uncertainty as to how the State might apply the new rules to the Keahole Plant. HELCO initiated engineering assessments to determine the feasibility of reducing the noise levels at the property line to comply with a 45/55 dBA standard in the event the DOH were to determine it applied to the Keahole Plant.

Q. Did HELCO discuss with the DOH how the new Statewide Noise Rules would be applied to Keahole (See KDC Position Statement, page 14)?

A. Yes. On April 18, 1997, Dr. Bruce Anderson, Deputy Director of DOH at the time, visited the Keahole Power Plant. During the course of the visit the subject of DOH's recently enacted Statewide Noise Rules was discussed. On April 23, 1997, DOH sent a letter to HELCO recommending that a Community Noise Permit application for construction be submitted and stated that HELCO should direct any questions to Jerry Haruno, DOH's Environmental Health Program Manager, Noise, Radiation and Indoor Air Quality Branch.

Q. Did HELCO follow through with DOH's suggestions in its letter?

A. Yes. On May 6, 1997, HELCO sent a letter to DOH stating that HELCO would contact Mr. Haruno regarding DOH's April 23, 1997 letter. On June 16, 1997, Mr. Jerry Haruno and Mr. Jimmy Ikeda of DOH met with Mr. Bud Bliemeister and Ms. Susan Li of HECO. During the meeting, the DOH representatives informed HELCO (1) that DOH applied the 70 dBA standard to the Keahole

Power Plant, (2) that DOH found the Keahole Power Plant to be in compliance with the current noise regulations, and (3) of the process DOH would follow if a legitimate noise complaint were submitted on any of HELCO's facilities.

Q. Did the DOH also take the same consistent position during the litigation proceedings in the Third Circuit Court?

A. In its initial Third Circuit pleadings in Civil No. 97-017K, DOH took the same consistent position that the noise pollution limits for the Keahole Power Plant were <u>not</u> 55 dBA daytime and 45 dBA nighttime for conservation zoned land on which the plant was located (i.e., the emitter site), and DOH would take noise measurements at the point of the noise impact (i.e., the receptor site) and measure compliance with regard to the noise standard applicable to the classification of that receptor site. For example, on November 13, 1997, DOH moved for summary judgment, stating that DOH reasonably interpreted HAR § 11-46-4 to allow it to take noise measurements at the point of the noise impact, at the residences nearest the station's property lines (i.e., the receptor site). On March 18, 1998, an Answer to Plaintiffs' First Amended Complaint was filed on behalf of the Director of DOH and BLNR. In answering Plaintiffs' First Amended Complaint, DOH stated that HAR § 11-46-4 spoke for itself, and denied that the noise pollution limits for the Keahole Power Plant were 55 dBA daytime and 45 dBA nighttime.

Q. Did DOH conduct noise inspections of the Keahole Power Plant in this timeframe?

A. Yes. Mr. Jerry Haruno of DOH stated in a November 1997 declaration that the two most recent site checks of the Keahole station were done on August 21, 1996, and February 13, 1997. The February 13, 1997, reading at the nearest residence in

Kona Palisades (zoned agricultural) was 37-38 dBA at 12:00 p.m., and 38-39 at 10:25 p.m. The readings at Mahi Cooper's residence (also zoned agricultural) on that date were 52-53 dBA at 12:00 p.m. and 55-56 dBA at 10:25 p.m. Mr. Haruno remarked that no violations were noted. (See HELCO-R-15C02.) These findings were consistent with DOH's interpretation of the noise rules, as conveyed to HELCO's representatives at the June 16, 1997 meeting. DOH measured the noise levels at the receptor sites.

Q. Was it unreasonable for HELCO to rely upon the guidance provided by the DOH (See KDC Position Statement, page 14)?

A. No. The DOH is the agency responsible for interpreting and enforcing the noise rules. Under the recommendation of Dr. Bruce Anderson, then Deputy Director at DOH, HELCO sought and received the guidance of Mr. Jerry Haruno in his capacity as the Program Manager for the Noise Branch.

DOH CHANGES INTERPRETATION OF NOISE RULE

Q. Did the DOH unexpectedly change its interpretation of its noise rules in 1999?

A. Yes. DOH changed its position on noise issues in February 1999. As described in further detail in HELCO-1501, pages 64-65, the first time the new position was disclosed was in a status conference in Civ. No. 97-017K. At that time, DOH's counsel verbally announced the change. The move was sufficiently unusual and important that the court ordered DOH to file a memorandum with the court stating and analyzing the changed position relative to the Keahole plant. On February 22, 1999, DOH formally documented its new position in a Supplemental Response, stating that the noise level standards for the property containing the source of the noise ("Emitting Property") would determine the applicable noise level and that such measurements would be taken at the boundary line or beyond the property line of the Emitting Property.

Q. How did this sudden change in interpretation by the DOH affect HELCO's Keahole Power Plant?

A. Under this new interpretation announced by the DOH Deputy AG, the noise limits for the Keahole Plant would now be 45/55 dBA along all property lines, instead of 70 dBA on the east, south, and west under the previous DOH interpretation.

Q. What did HELCO do in response to this sudden change in the DOH's interpretation?

A. HELCO challenged the constitutionality of the noise rules as newly interpreted by DOH, first at the Circuit Court level. In March 1999 the Third Circuit Court ruled that the noise rules were not invalid "on its face" (i.e., as generally applied) and that the 55 dBA daytime/45 dBA nighttime standard applied to conservation land. My understanding was that the court explicitly did not rule on any potential claims against DOH for applying that standard specifically to the Keahole plant, pending any enforcement action by DOH. HELCO then appealed the ruling to the Supreme Court.

Q. Did the DOH eventually enforce the new interpretation of the noise rules at Keahole?

A. Yes. In June of 2002 (over three years after the court's ruling), in response to a complaint from the occupant of a neighboring lot, the DOH conducted an inspection of the Keahole property and found noise levels to be slightly above the 45 dBA limit along the west property line at night. In response, HELCO applied for and received a noise permit in July of 2002 from the DOH in accordance with

HAR § 11-46-7. This noise permit allows exceedances while the Company works toward resolving the noise issues.

Q. What other action did HELCO take in response to the new interpretation?

A. At the same time (i.e., in 1999), HELCO initiated design engineering assessments for meeting the 45/55 dBA standard along its property lines. The engineering assessments now pertained not only to the new plant and equipment for the CT-4/CT-5/ST-7 project, but also to the existing plant equipment and operations as well.

Q. By applying for the noise permit and taking action to implement noise mitigation measures, was HELCO admitting that it should have known that the Keahole plant was subject to the 55/45 dBA noise standard?

A. No. Such actions were taken in an effort not to further stall construction while the appeal was pending. Consistent with this, in its application for the noise permit HELCO stated, "HELCO is also challenging in court the constitutionality of the current noise rules as promulgated. Submittal of this application and our desire to comply with the noise regulations of the State Department of Health should not be considered a waiver of HELCO's rights or deemed an admission that these regulations are applicable or legal."

USE OF ON-SITE WELL FOR SOURCE WATER

Q. How did HELCO plan to meet the source water needs for the Keahole Project?

A. HELCO planned to construct its own on-site water wells to meet the operational needs of both the new plant and equipment as well as the existing plant.

Q. Why was the on-site well water selected as the proposed source?

A. Since the water purity requirements for the plant equipment require treatment of the water regardless of whether the source is potable or non-potable, HELCO proceeded with seeking a non-potable on-site source as a means to secure a reliable supply, reduce costs, and not burden the County water supply system.

Q. Did interveners challenge HELCO's ability to use the brackish groundwater from its on-site wells?

A. Yes. As explained in Docket No. 7623, Waimana Enterprises, an intervening independent power producer with competing plans to build its own power plant on a Department of Hawaiian Home Lands site in Kawaihae, filed a petition for declaratory ruling with the Board of Land and Natural Resources ("BLNR") requesting a ruling that BLNR was the proper body to make determinations concerning HELCO's right to use the groundwater under its Keahole site, and that HELCO did not have the right to use the groundwater under the Keahole site.

Q. What was the alleged basis for Waimana's claim?

A. The Keahole site, which HELCO purchased from the State, was formerly "ceded" land. However, it was not clear whether the groundwater had "ceded" property status. It was HELCO's understanding that the relationship between "ceded" land and appurtenant water was unsettled under Hawaii law.

Q. What did HELCO do to ensure a reliable source of water would be available for the project (See KDC Position Statement, page 21)?

A. Due to the unclear status of the potentially "ceded" water, HELCO obtained an agreement with the County Department of Water Supply for a supply of potable water as a contingency.

Q. How did HELCO eventually obtain the rights to the groundwater?

A. The issue of the process to obtain the rights to use the groundwater took a while to resolve. HELCO initially applied for a brackish water license from BLNR in 1998. That request was stalled and came up for hearing again in mid-2000, but due to uncertainty within the agency as to the proper means of processing the request, it remained unresolved for a time. Eventually, HELCO obtained a revocable water permit in December 2003, then eventually applied for the right to bid on a long-term water lease and was the successful bidder. In July 2004, HELCO executed the long-term lease with the State to use the groundwater.

Q. Were there any challenges to these groundwater rights?

A. Yes, both were challenged by Waimana, and the long-term lease was also challenged by another group. The appeals were denied at the Circuit Court in 2004 and 2005, respectively, and then at the Supreme Court in 2006

Q. Did the timing of obtaining the groundwater rights adversely impact the schedule for installing or operating CT-4 or CT-5 as KDC claims? (KDC Position Statement, pages 12 and 21.)

A. No, there was no adverse impact on timing.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.

Hawaiian Electric Company, Inc.

BARRY M. NAKAMOTO

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc 170 Ala Moana Blvd P.O. Box 2750 Honolulu, Hawaii 96840
Position:	Principal Scientist Environmental Department
Years of Service:	17
Education:	M.B.A., Hawaii Pacific University, Bachelor of Science in Mechanical Engineering, Santa Clara University
Experience:	2000 - Present Senior Scientist and Principal, Air & Noise Division,Environmental Department, Hawaiian Electric Company, Inc. 1995 - 2000 Project Manager, Planning & Engineering Department, Hawaiian Electric Company, Inc. 1991 -1995 Mechanical Engineer, Engineering Department, Hawaiian Electric Company, Inc. 1989 - 1991 Mechanical Designer, Engineering Department, Hawaiian Electric Company, Inc.
Previous Testimonies:	Docket No. 97-0420 - HELCO 1999 Test Year Docket No. 7956 - KCP PPA Negotiations Docket No. 94-0140 - HELCO 1996 Test Year Docket No. 94-0079 - Enserch PPA Negotiations Docket No. 7259 - HELCO IRP Docket No. 7623 - HELCO Keahole CT-5/ST-7

JOHN WAIHEE
GOVERNOR OF HAWAII

STATE OF HAWAII
DEPARTMENT OF HEALTH
P. O. BOX 3378
HONOLULU, HAWAII 96801

JOHN C. LEWIN, M.D.
DIRECTOR OF HEALTH

In reply, please refer to:
File:

June 21, 1994

Mr. Warren Lee
President
Hawaii Electric Light Company
P. O. Box 1027
Hilo, Hawaii 96721-1027

Dear Mr. Lee:

We are attaching a copy of a report of sound levels emanating from the Kona power plant operations located off of Queen Kaahumanu Highway, Keahole, Kona. The survey was conducted in response to a complaint.

The results show that the sound levels from the power plant operations are within the allowable noise levels for Agricultural Zoning Districts, as referenced in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu.

It is recommended that the equipment be kept in good operating condition so that there will be no increase in the present noise levels.

I believe that the report is self-explanatory. Should you have any questions, please contact me at 586-4700.

Very truly yours,

Daryn A. Yamada
Supervisor, Noise Section
Noise and Radiation Branch

EXHIBIT "A"

STATE OF HAWAII
DEPARTMENT OF HEALTH
NOISE AND RADIATION BRANCH
NOISE SURVEY

Company/Organization Hawaii Electric Light Company Date June 1, 1994

Address P. O. Box 1027 Phone No.
Type of Activity Electric Company
Person(s) Contacted and Position Warren Lee, President

Noise Source Power plant operations

Instrument Used B&K 2225 Sound Level Meter Weighting Network A
Meter Response Slow Calibrated:Before 93.8 After 93.8

Location of Survey end of Pukiawe Street Wind Velocity 0-5 mph

Time	dBA Range	Distance from Source	Comments
			Noise levels taken at the cul de sac on Pukiawe Street.
1:55 pm	34-35		Ambient noise levels taken on Laui Street. Power plant not audible.
1:45 pm	50-53	approximately 200 feet	Power plant in operation.
6:20 pm	39-40		Ambient noise levels taken on the corner of Kaimiani and Pukiawe Streets. Power plant not audible.
6:00 pm	53-55	approximately 200 feet	Power plant in operation.

BACKGROUND:

In response to a complaint, a noise survey was conducted on June 1, 1994 at Pukiawe Street. The noise source was operation of a power plant located off of Queen Kaahumanu Highway, Keahole, Kona.

A calibrated Bruel & Kjaer Sound Level Meter was used with the "A" weighting network, "slow" meter response, and a windscreen attached to the microphone. Noise level measurements were taken south of the power plant at the cul de sac on Pukiawe Street (see attached sheet for specific distances). The respondent's property and neighboring properties are zoned Agricultural.

FINDINGS AND DISCUSSIONS:

See attached sheet for noise level readings.

For comparative purposes, the allowable noise levels as provided in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu are referenced. The allowable noise levels at or beyond the property line for Agricultural Zoning Districts are 70 dBA for daytime (7:00 a.m. to 10:00 p.m.) and 70 dBA for nighttime (10:00 p.m. to 7:00 a.m.).

Excessive noise is defined as any sound or sequence of sounds to which an individual is exposed and which exceeds the allowable noise level more than 10% of the time in any 20-minute period.

CONCLUSIONS AND RECOMMENDATIONS:

The noise levels emitted by the power plant operations on the survey date are within the allowable levels as stated in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu.

It is recommended that the equipment be kept in good operating condition so that there will be no increase in the present levels.

Daryn A. Yamada
Environmental Health Specialist

NOV 14 1997
Xc: Hirose

FILED

Nov 13 12 42 PM '97

Ex Officio Clerk
Circuit Court 3rd Circuit

MARGERY S. BRONSTER 4750
Attorney General of Hawaii

HEIDI M. RIAN 3473
MADELEINE AUSTIN 6391
ELIZABETH A. SCHALLER 5361
RANDALL Y.K. YOUNG 2810
Deputy Attorneys General
Kekuanao'a Building, Room 200
465 South King Street
Honolulu, Hawaii 96813
Telephone: (808) 587-3050

Attorneys for Defendants Lawrence Miike, Director
of Department of Health, in his official capacity,
Board of Land and Natural Resources, and State of Hawaii

IN THE CIRCUIT COURT OF THE THIRD CIRCUIT

STATE OF HAWAII

KEAHOLE DEFENSE COALITION, a Hawaii nonprofit corporation, THOMAS B. O'TOOLE, CATHERINE CARTER O'TOOLE, and BRAD HOUSER, Plaintiffs, vs. LAWRENCE MIIKE, Director of Health, State of Hawaii; BOARD OF LAND AND NATURAL RESOURCES, State of Hawaii; HAWAII ELECTRIC LIGHT COMPANY, INC., a Hawaii Corporation. Defendants.	CIVIL NO. 97-017K (Kona) (Declaratory Judgment) DEFENDANTS LAWRENCE MIIKE AND BOARD OF LAND AND NATURAL RESOURCES' MOTION FOR SUMMARY JUDGMENT; MEMORANDUM IN SUPPORT OF MOTION; DECLARATION OF NOLAN S. HIRAI; EXHIBITS "A" - "H"; DECLARATION OF ELIZABETH A. SCHALLER; EXHIBITS "A" - "E"; DECLARATION OF JERRY HARUNO; EXHIBITS "A" - "B"; NOTICE OF HEARING ON MOTION; CERTIFICATE OF SERVICE DATE: December 1, 1997 TIME: 11:00 a.m. JUDGE: RONALD IBARRA

DEFENDANTS LAWRENCE MIIKE AND BOARD OF LAND
AND NATURAL RESOURCES' MOTION FOR SUMMARY JUDGMENT

IN THE CIRCUIT COURT OF THE THIRD CIRCUIT

STATE OF HAWAII

KEAHOLE DEFENSE COALITION, a Hawaii nonprofit corporation, THOMAS B. O'TOOLE, CATHERINE CARTER O'TOOLE, and BRAD HOUSER, Plaintiffs, vs. LAWRENCE MIIKE, Director of Health, State of Hawaii; BOARD OF LAND AND NATURAL RESOURCES, State of Hawaii; HAWAII ELECTRIC LIGHT COMPANY, INC., a Hawaii Corporation. Defendants.	CIVIL NO. 97-017K (Kona) (Declaratory Judgment) DECLARATION OF JERRY HARUNO; EXHIBITS "A" - "B"

DECLARATION OF JERRY HARUNO

1. I am the Environmental Health Program Manager for the Noise, Radiation and Indoor Air Quality Branch of the Department of Health, State of Hawaii, and have been employed by the Department since 1972, and make the following statements based on personal information unless otherwise indicated.

2. On September 23, 1996, statewide noise rules regulating certain types of stationary noise went into effect for the State of Hawaii.

3. Prior to September, 1996, the only noise regulations in effect were community wide regulations for the island of Oahu only.

4. The Noise Program of the Department of Health ("Noise Program") never received any written or oral complaints from the named plaintiffs in this case.

to noise in the area surrounding the Keahole station. Mr. Cooper's home is the closest residence to the Keahole power station.

6. On June 1, 1994, inspector Daryn Yamada investigated Mr. Cooper's noise complaint at the Keahole station and found there to be no violation. See Exhibit A attached to this affidavit.

7. Because there were no statewide noise rules in effect at the time Mr. Cooper's complaint was investigated, the inspector used as a comparison the noise standards for the island of Oahu (Title 11 H.A.R. Ch. 43) and assumed a zoning of "agricultural" in taking the readings. The maximum noise levels recorded during the measurements were between 34 and 55 from Mr. Cooper's home and were within the standards for the island of Oahu that were used for guidance only in this case. The allowable noise levels at or beyond the property line for agricultural zoning under the former Oahu standards (11 H.A.R. Ch. 43) were 70 dBA.

8. Since the time of Mr. Cooper's complaint, there has been no complaint regarding excessive noise emanating from the station that has been brought to the attention of the Noise Program.

9. Since the time the new statewide noise rules went into effect in September of 1996, the Noise Program has received no complaint regarding excessive noise emanating from the Keahole station.

10. The two most recent site checks of the Keahole station were done on August 21, 1996, and February 13, 1997. The February 13, 1997, reading at the nearest residence in Kona palisades (zoned agricultural) was 37-38 dBA at 12:00 p.m., and 38-39 at 10:25 p.m. The readings at Mahi Cooper's residence on that date were 52-53 dBA at 12:00 p.m. and 55-56 dBA at 10:25 p.m. See Exhibit B attached. No violations were noted.

I declare under the penalty of perjury that the foregoing is true and correct.

Executed on October 6, 1997, at Honolulu, Hawaii.

Jerry Havuno

Jerry Havuno

STATE OF HAWAII
DEPARTMENT OF HEALTH
P. O. BOX 3378
HONOLULU, HAWAII 96801

June 21, 1994

Mr. Warren Lee
President
Hawaii Electric Light Company
P. O. Box 1027
Hilo, Hawaii 96721-1027

Dear Mr. Lee:

We are attaching a copy of a report of sound levels emanating from the Kona power plant operations located off of Queen Kaahumanu Highway, Keahole, Kona. The survey was conducted in response to a complaint.

The results show that the sound levels from the power plant operations are within the allowable noise levels for Agricultural Zoning Districts, as referenced in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu.

It is recommended that the equipment be kept in good operating condition so that there will be no increase in the present noise levels.

I believe that the report is self-explanatory. Should you have any questions, please contact me at 586-4700.

Very truly yours,

Daryn A. Yamada
Supervisor, Noise Section
Noise and Radiation Branch

EXHIBIT "A"

STATE OF HAWAII
DEPARTMENT OF HEALTH
NOISE AND RADIATION BRANCH
NOISE SURVEY

Company/Organization Hawaii Electric Light Company Date June 1, 1994

Address P. O. Box 1027 Phone No.
Type of Activity Electric Company
Person(s) Contacted and Position Warren Lee, President

Noise Source Power plant operations

Instrument Used B&K 2225 Sound Level Meter Weighting Network A
Meter Response Slow Calibrated: Before 93.8 After 93.8

Location of Survey end of Pukiawe Street Wind Velocity 0-5 mph

Time	dBA Range	Distance from Source	Comments
			Noise levels taken at the cul de sac on Pukiawe Street.
1:55 pm	34-35		Ambient noise levels taken on Laui Street. Power plant not audible.
1:45 pm	50-53	approximately 200 feet	Power plant in operation.
6:20 pm	39-40		Ambient noise levels taken on the corner of Kaimiani and Pukiawe Streets. Power plant not audible.
6:00 pm	53-55	approximately 200 feet	Power plant in operation.

BACKGROUND:

In response to a complaint, a noise survey was conducted on June 1, 1994 at Pukiawe Street. The noise source was operation of a power plant located off of Queen Kaahumanu Highway, Keahole, Kona.

A calibrated Bruel & Kjaer Sound Level Meter was used with the "A" weighting network, "slow" meter response, and a windscreen attached to the microphone. Noise level measurements were taken south of the power plant at the cul de sac on Pukiawe Street (see attached sheet for specific distances). The respondent's property and neighboring properties are zoned Agricultural.

FINDINGS AND DISCUSSIONS:

See attached sheet for noise level readings.

For comparative purposes, the allowable noise levels as provided in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu are referenced. The allowable noise levels at or beyond the property line for Agricultural Zoning Districts are 70 dBA for daytime (7:00 a.m. to 10:00 p.m.) and 70 dBA for nighttime (10:00 p.m. to 7:00 a.m.).

Excessive noise is defined as any sound or sequence of sounds to which an individual is exposed and which exceeds the allowable noise level more than 10% of the time in any 20-minute period.

CONCLUSIONS AND RECOMMENDATIONS:

The noise levels emitted by the power plant operations on the survey date are within the allowable levels as stated in Title 11, Administrative Rules Chapter 43, Community Noise Control for Oahu.

It is recommended that the equipment be kept in good operating condition so that there will be no increase in the present levels.

Daryn A. Yamada
Environmental Health Specialist

September 10, 1996

To: Daryn Yamada

From: James Toma

Re: The schedule of events for the recent Big Island Trip.

Wednesday, August 21, 1996

8:20 a.m. - 9:15 a.m.	Flight from Honolulu to Hilo
9:15 a.m. - 9:30 a.m.	Pickup luggage
9:30 a.m. - 10:00 a.m.	Secure rental car (It took a while because they didn't have our car so we took a jeep instead).
10:00 a.m. - 10:30 a.m.	Check-in at Hilo office, brief meeting
10:45 a.m.	Site check in Keaau on Complaint No. HA-96-005
11:15 a.m. - 12:15 p.m.	Repair phone line for geothermal stationary monitor.
1:00 p.m. - 6:00 p.m.	Travel from Puna to Kona.
6:00 p.m. - 6:15 p.m.	Check-in at the hotel.
6:30 p.m. - 7:00 p.m.	Site check at the Helco power plant. Readings at the front entrance of the power plant ranged from 61-62 dBA.
9:30 p.m. - 10:30 p.m.	Site check at Huggo's in Kona. The music in not audible at complainant's apartment and barely audible at their property line.

Thursday, August 22, 1996

2:00 p.m. - 3:00 p.m.	Meeting with George Iuta of Helco at the Kona plant. Only the 6 smaller diesel units are operational, the larger unit is being repaired and won't be operating

EXHIBIT "B"

for a few weeks. Chapter 46 was explained to George while a tour of the plant was being conducted. According to George only 2 of the 6 unit are running now. All 6 units should be operating when electricity is in high demand (from about 6:00 p.m.).

8:45 p.m. - 9:15 p.m. Readings taken of the Kona power plant. The background noise levels were 37-38 dBA. Readings at the Cul-de-Sac by Mahi Cooper's home were 56-57 dBA.

9:35 p.m. Readings taken at the driveway of the Hawaiian Legends macadamia nut processing plant were 54-56 dBA.

Friday, August 23, 1996

10:35 a.m. Readings taken of the power plant off Banyon Dr. in Hilo were 61-62 dBA, approx. 125' from the plant.

12:00 p.m. Readings taken of the power plant off Railroad Ave. in Hilo were 70-72 dBA, approx. 150 ', from the plant.

[illegible], 18, 1997

To: Jerry Y. [illegible], Program Manager
Noise, Radiation & Indoor Air Quality Branch

From: Daryn A. Yamada, Supervisor
Noise Section

Subject: Big Island Trip (February [illegible] 1997)
D. Yamada & [illegible] Toma

Thursday, February 13, 1997

09:30 a.m.	Meeting with Kona Sanitation.
11:00 a.m.	Site check at King Kamehameha Hotel with Larry Shiro. According to the hotel Engineer (Damian Souza), they were having problems with an exhaust fan timer that wasn't shutting the fan off at 10:00 p.m.. They have since fixed the fan. Readings on the fan (56 dBA) were within the background levels (54 dBA). A nighttime survey was scheduled for 9:30 p.m. for that night. Photographs taken, to be submitted later.
11:45 a.m.	Telephoned Judy Thurston from Kona Sanitation office - not available.
12:00 p.m.	Site check for the Keahou Electric power plant. Readings taken at the nearest residence in Kona Palisades (Zoned Agriculture) were only background (37-38 dBA) because the plant was inaudible. The readings at Mahi Cooper's were 52-53 dBA.
08:00 p.m.	Site check at the Hawaiian Legend's macadamia nut farm. No activity at the processing plant.
09:00 p.m.	Telephoned Judy Thurston - answering machine on.
09:30 p.m.	Site check at King Kamehameha Hotel. The equipment that is generating the most noise is not from an exhaust fan but from refrigeration compressors. Noise levels from the nearest property line for all equipment were 55 dBA. Background noise levels were not taken because equipment on roof next to the loading dock were 53 dBA.
10:25 p.m.	Site check at the power plant. The readings at Mahi Cooper's were 55-56 dBA. The readings at the entrance to Kona Palisades were 38-39 dBA, with the power plant being barely audible with the crickets. The readings at the residentially zoned sub-division mauka of Kona Palisades were less than 34 dBA, with the power plant being barely audible.

Friday, February 14, 1997

09:00 a.m. Meeting with Kona Sanitation. Consultant for the King Kamehameha Hotel (Judy [illegible]) was also contacted.

11:00 a.m. Site check for future electric plant [illegible] - photograph taken to be submitted later.

12:30 p.m. Meeting with Jon Nakashima in Waimea to investigate a noise complaint of a portable generator in Waimea. Complaint may have been resolved.

REBUTTAL TESTIMONY OF

GUY PASCO, P.E.

SENIOR SUPERVISING ENGINEER
POWER SUPPLY ENGINEERING DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Keahole Noise Mitigation

INTRODUCTION

Q. Please state your name and business address.

A. My name is Guy Pasco and my business address is P.O. Box 2750, Honolulu, Hawaii, 96840. My resume is attached as HELCO-R-15D00.

Q. By whom are you employed and in what capacity?

A. I am the Mechanical Senior Supervising Engineer in the Power Supply Engineering Department at Hawaiian Electric Company, Inc. ("HECO"). I am submitting testimony on behalf of Hawaii Electric Light Company, Inc. ("HELCO").

Q. What will your rebuttal testimony cover?

A. My testimony will cover HELCO's actions to mitigate noise from Keahole CT-4 and CT-5.

Q. What is your involvement in the CT-4 and CT-5 projects?

A. I was the Project Engineer from January 2002 through September 2004.

KEAHOLE CT-4 AND CT-5 NOISE

Q. Can you summarize the noise mitigation measures that were designed and implemented after DOH informed HELCO that noise compliance would be measured on the basis of the emitting property?

A. Appendix A, pages 10 through 12, and Appendix B, pages 14 and 15 of HELCO's Final Cost Report detail the noise mitigation measures that were necessary to meet the emitter-based 55 dBA daytime and 45 dBA nighttime noise limits for conservation land. The efforts related to the CT packages included retrofitting silencers to the turbine-compressor air intakes, retrofitting hot-gas and bypass gas silencers in the exhaust ducting, retrofitting silencers to the CT package ventilation inlets and outlets, erecting a secondary acoustic enclosure around each CT, and installing shrouds around the exhaust ductwork. Noise countermeasures for the CT support equipment included erecting secondary acoustic enclosures around the water injection machinery skids, the fuel forwarding pump skids, the fuel centrifuge skid, and the compressor cooling machinery skid, and installing noise barrier walls around the step-up transformers, raw water pumps, and lube oil cooler skids. HELCO-R-15D01 contains photos of this equipment.

Q. On page 13 of KDC's position statement, HELCO is criticized for not requiring design or material upgrades for CT-4 and CT-5 at the time of their purchase. The noise mitigation measures listed above appear to be modifications and retrofit of the equipment purchased by HELCO. Could lower cost low-noise features have instead been originally provided by the equipment manufacturers at the time of purchase, eliminating the later retrofit and modification effort?

A. No, the 55 dBA daytime and 45 dBA nighttime property boundary noise level requirements are at the extreme low end of the acoustic performance range for utility generation equipment. Considerable countermeasures and engineering controls were utilized to achieve the 55 dBA / 45 dBA performance of this machinery. If these acoustic requirements had been included in the original purchase, the equipment manufacturers would have had to utilize the same custom retrofit techniques ultimately carried out by HELCO.

Q. Can you explain the difference between 55 dBA and 45 dBA?

A. The decibel scale that noise is measured with is logarithmic, not linear. Because of this logarithmic nature, every 10 dBA difference represents a 10-fold increase in intensity of noise. A 55 dBA sound is 10 times as intense as a 45 dBA sound.

Q. What is the untreated noise level from a combustion turbine package?

A. The standard noise control for the Stewart & Stevenson LM-2500 combustion turbine package results in near field noise levels of 90 dBA at 3′ away.

Q. Can you provide specific noise level examples that we can relate to?

A. As a point of reference, 110 dBA is the same as a jet plane flyover directly overhead. 100 dBA is the sound of a motorcycle 25′ away. 90 dBA is about as loud as being right next to a food blender. 80 dBA is as loud as being 10′ away from a vacuum cleaner. 70 dBA is equivalent to inside the cabin of a 757 airplane while in flight. 60 dBA is normal conversation. 50 dBA is a quiet office. 40 dBA is like the inside of most libraries.

Q. How quiet can it get at Keahole?

A. At Keahole in the middle of the night, with no airport activity, absolutely no traffic on the highway, and with no power plant machinery running, the ambient (background) noise varies between 38 dBA and 45 dBA, depending whether there is a breeze and if crickets are chirping.

Q. How did HELCO determine which CT-4 and CT-5 components required silencing in order to comply with the new 55 dBA daytime / 45 dBA nighttime standards?

A. HELCO's design consultant Stone & Webster performed a noise source evaluation to identify the major equipment noise sources. They obtained the uncontrolled sound levels from the equipment manufacturers, and from information on other projects of similar size and sound levels. The Keahole site was then modeled using a computer noise prediction and contouring program. The noise emissions and necessary attenuation for each noise source were then determined.

Stone & Webster developed a Simple Cycle Noise Abatement performance specification for the supply of acoustic countermeasures for CT-4 and CT-5. The specification included technical, performance, and code requirements, as well as a list of octave band sound power levels and operating parameters from the CT-4 and CT-5 equipment and support systems. These acoustic countermeasures were bid out to firms who specialize in the field of industrial noise abatement. Stone & Webster performed the evaluation of proposals, and provided a purchase recommendation based on a cost and technical analysis of the quotes.

The suppliers for the noise abatement equipment independently utilized sophisticated acoustic modeling software as the basis for their proposals. Using an iterative process, the noise abatement suppliers were able to introduce various noise treatments on the different sources in their acoustic model, and obtain a solution to meet the overall acoustic targets at the least cost to HELCO.

Q. The Consumer Advocate contended that certain Keahole costs, including noise abatement, should have been less than the amounts actually incurred. Do you agree with this position? (See CA-T-3, page 95.)

A. No. HELCO's acoustic approach to the planning of the project, including designing not to exceed the CDUP noise level limits and basing noise performance on DOH's receptor-based enforcement of the noise rules, was appropriate. As explained in the testimony of Mr. Nakamoto, HELCO RT-15C, after the Statewide Noise Rules were promulgated and after DOH changed its interpretation of the noise rules, HELCO used computer acoustic modeling software and implemented noise countermeasures by obtaining competitive proposals to mitigate noise at the least cost. However, the execution of the noise abatement work after CT-4 and CT-5 were installed did necessitate some additional construction work.

Q. Please explain.

A. After negotiation of the 2003 Settlement Agreement and actions by the Third Circuit Court and Hawaii Supreme Court permitted installation of CT-4 and CT-5 to be completed, HELCO began construction of CT-4 and CT-5. Materials and equipment were on-hand for erection of CT-4 and CT-5 per the original plant design, but due to the 2002 work stoppage, procurement of the acoustic countermeasures had been put on hold. Although some of the raw materials for the noise abatement equipment were in storage on the mainland, it was going to take time for the suppliers to gear up and resume factory fabrication and delivery activities. Additionally, it was estimated that the installation of the noise abatement materials and equipment would add about 10 weeks to the construction of each unit. The CT-4 and CT-5 construction was therefore restarted without the noise abatement equipment, with priority to place critical generation assets into service and a plan to perform a phased retrofit of the noise abatement equipment after all components were delivered on site.

Q. Was this plan successful?

A. This plan was successful in that CT-4 was able to go into commercial service on May 25, 2004, and CT-5 about a month later on June 30, 2004. While the units were running, construction of most of the noise abatement structures, foundations, and support equipment was accomplished. Each unit was shut down later in 2004 to allow retrofit of components that could not be installed with the units running.

Q. What was the estimated cost impact due to the duplication of certain construction efforts related to retrofitting noise abatement equipment?

A. The estimated cost of duplicated construction, that is, demolition of the exhaust silencers provided by Stewart and Stevenson, dismantling of the combustion turbine air intakes and ventilation equipment, and re-construction work associated with erecting the combustion turbine exhaust silencers, air intake silencers, and package ventilation silencers, totaled $235,745. HELCO-R-15D02 breaks out these costs from the overall noise abatement cost.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.

Hawaiian Electric Company, Inc.

Guy Pasco, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. P.O. Box 2750 Honolulu, HI 96840
Position:	Senior Supervising Engineer Power Supply Engineering Department
Education:	Bachelor of Science in Mechanical Engineering University of Hawaii, 1988
Other Qualifications:	Licensed Professional Engineer State of Hawaii, Mechanical Branch - 1994
Experience:	HAWAIIAN ELECTRIC COMPANY, INC.

2004 - present
Senior Supervising Engineer
Power Supply Engineering Department
Hawaiian Electric Company, Inc.

1996 - 2004
Mechanical Engineer II, Engineering Department,
Hawaiian Electric Company, Inc.

1994 - 1996
Mechanical Engineer I, Engineering Department,
Hawaiian Electric Company, Inc.

1991 - 1994
Designer II, Engineering Department,
Hawaiian Electric Company, Inc.

1988 - 1991
Designer I, Engineering Department,
Hawaiian Electric Company, Inc.

U.S. COAST GUARD RESERVE

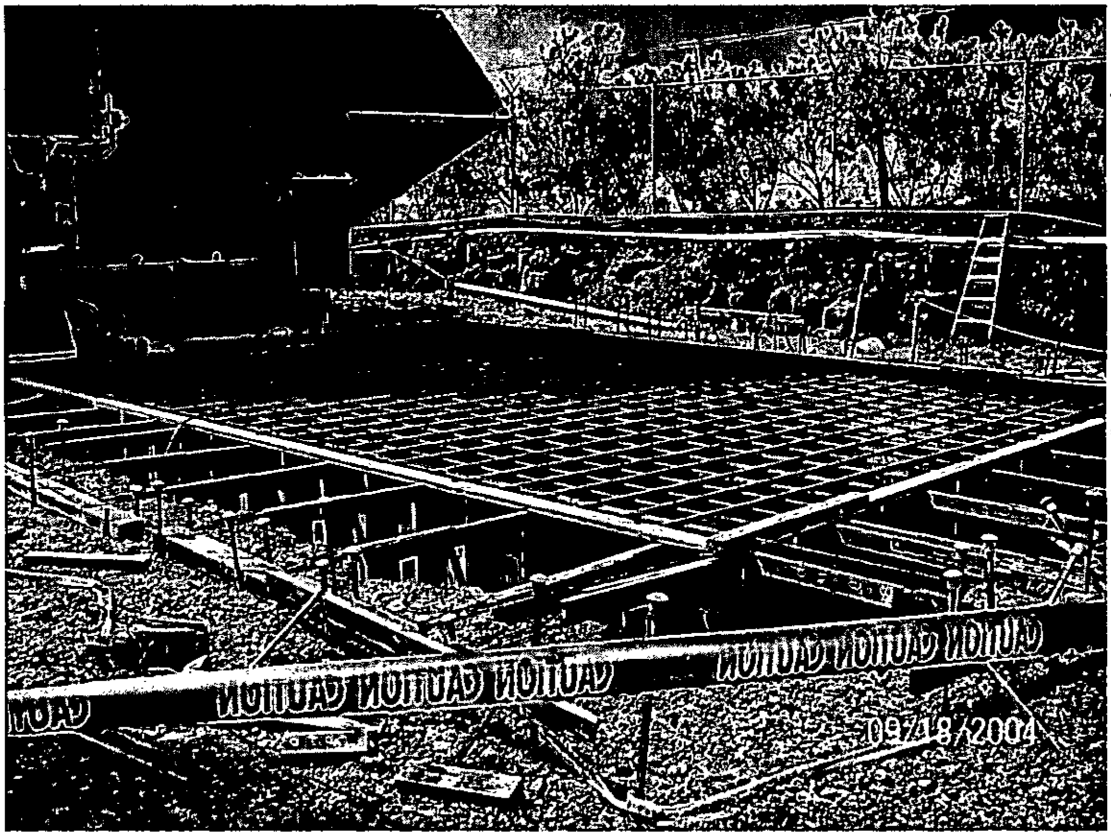
1985 - present
Master Chief Machinery Technician
CG Base Sand Island, Hawaii

DEPARTMENT OF THE NAVY

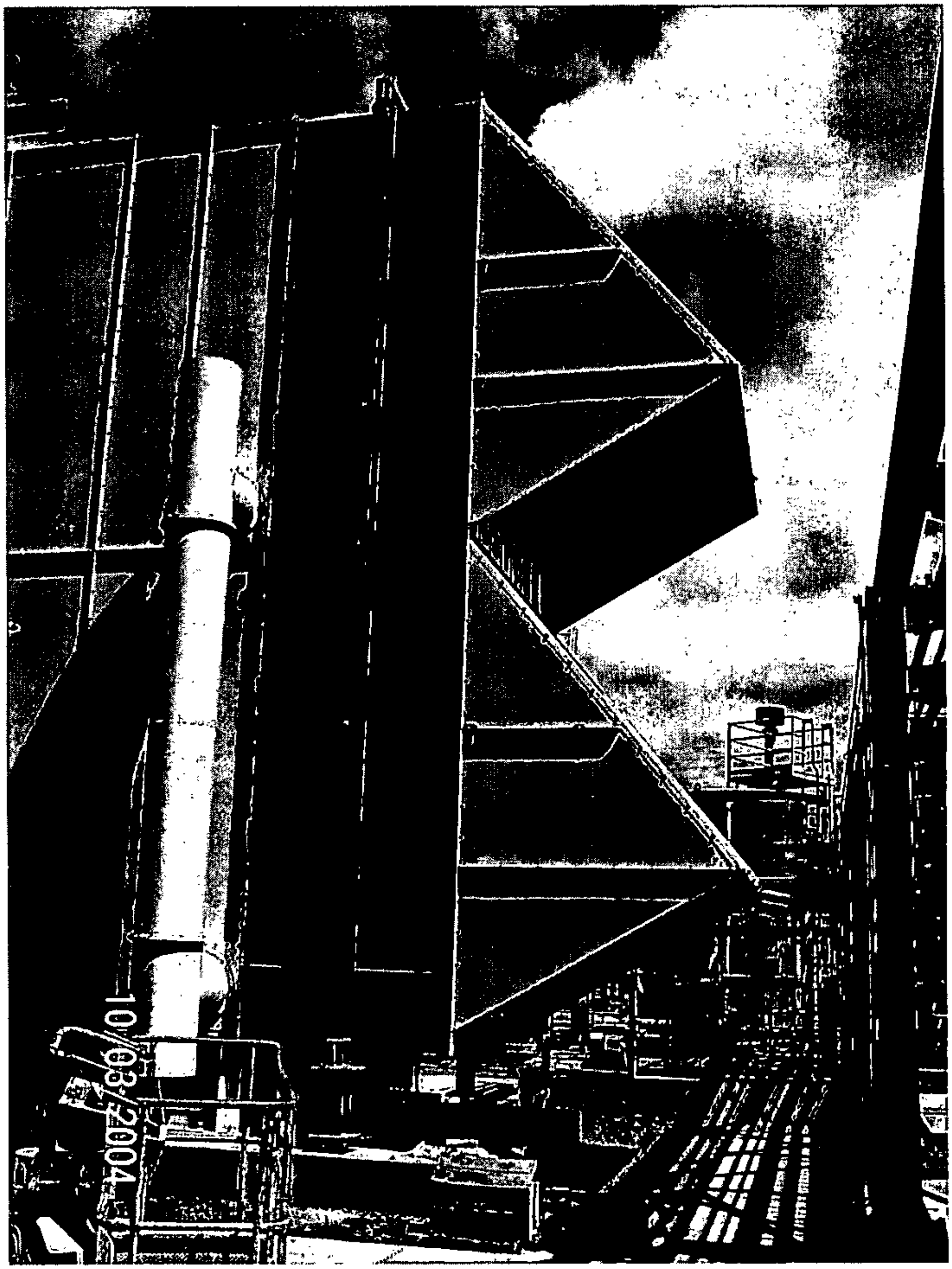
1988
Assistant Shift Test Engineer Trainee
Pearl Harbor Naval Shipyard

1976 – 1983
Nuclear Machinist Mate
Submarine Service

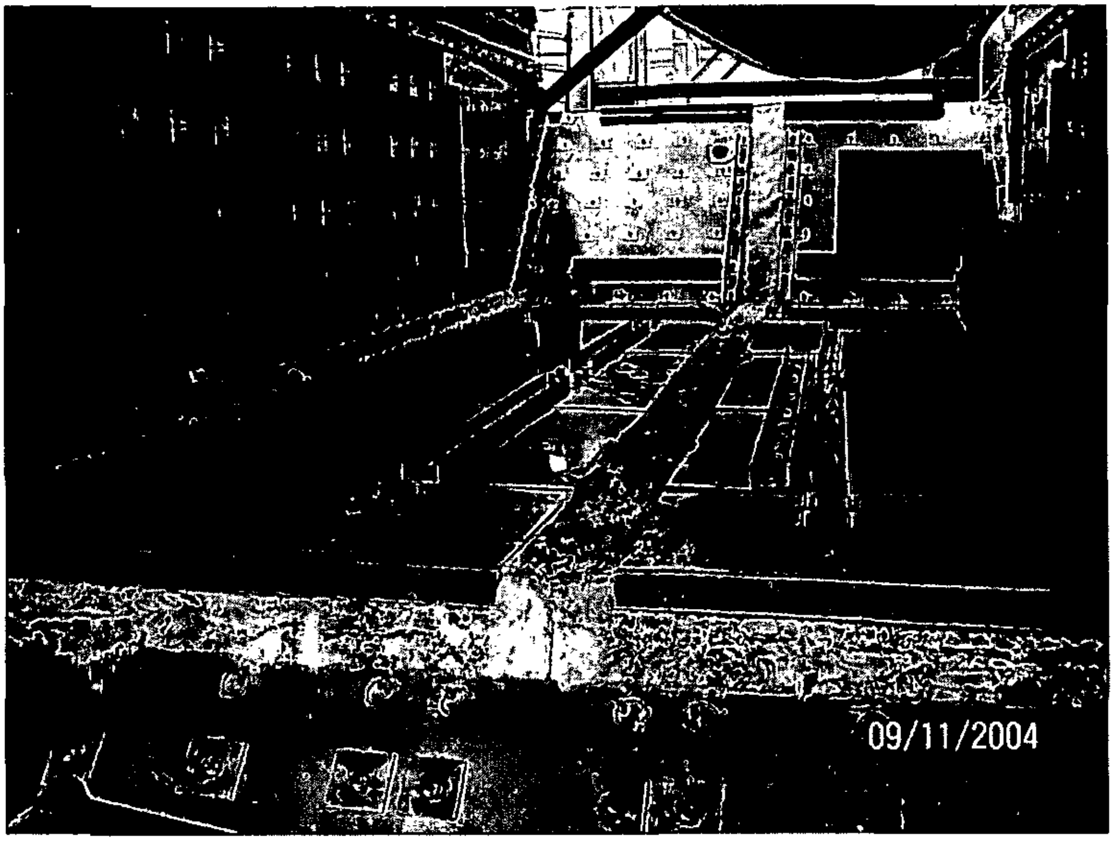
NOISE ABATEMENT PHOTOS



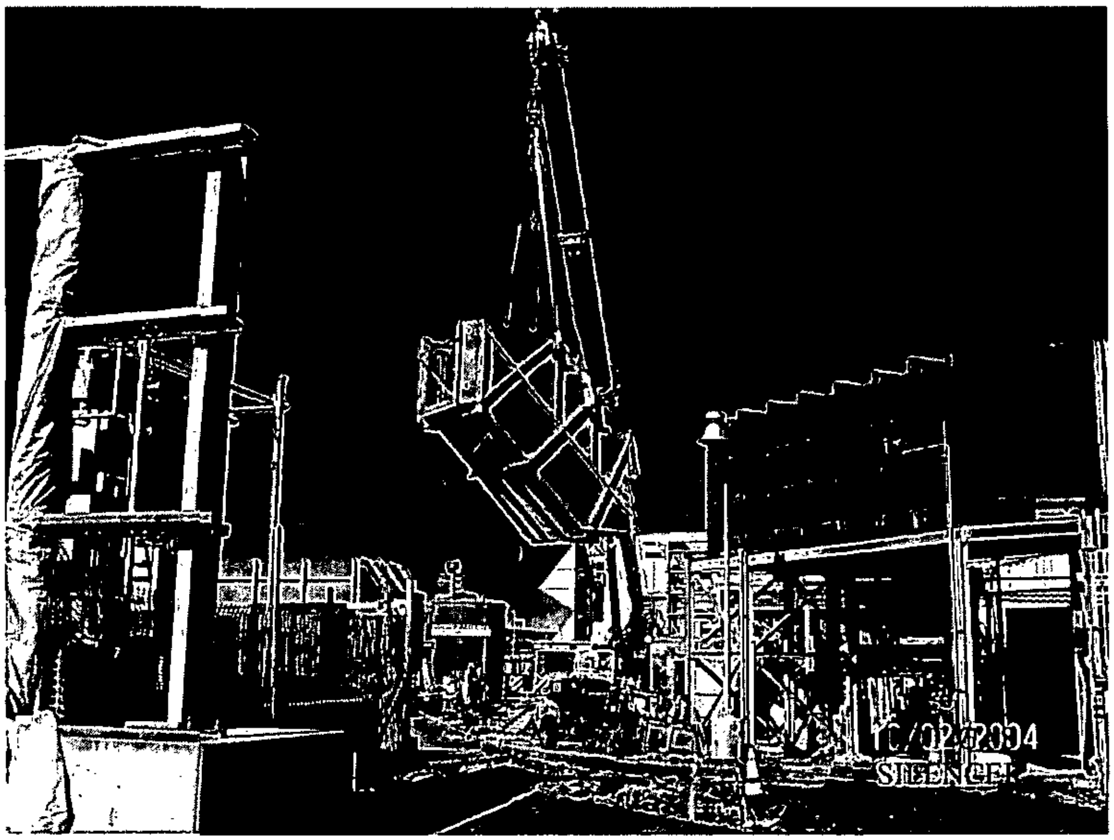
FOUNDATION PREPARATIONS FOR CT-5 INTAKE AIR SILENCER. STEWART & STEVENSON INLET AIR FILTER HOUSING IS IN THE LEFT BACKGROUND.



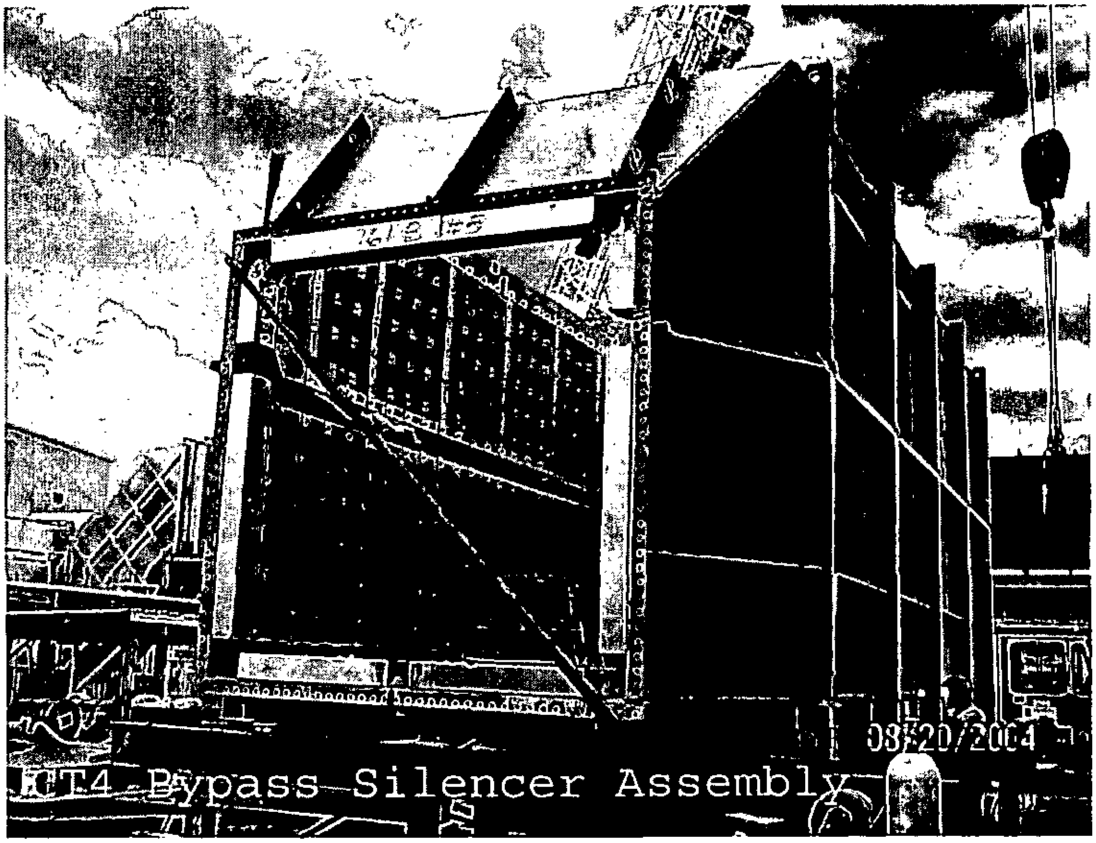
CT-4 INLET AIR SILENCER (DARK PORTION OF DUCTWORK)—INLET AIR FILTER HOUSING IS TO THE LEFT, AND SALVAGED RAIN HOODS ARE TO THE RIGHT. THIS STRUCTURE IS APPROXIMATELY 31' TALL.



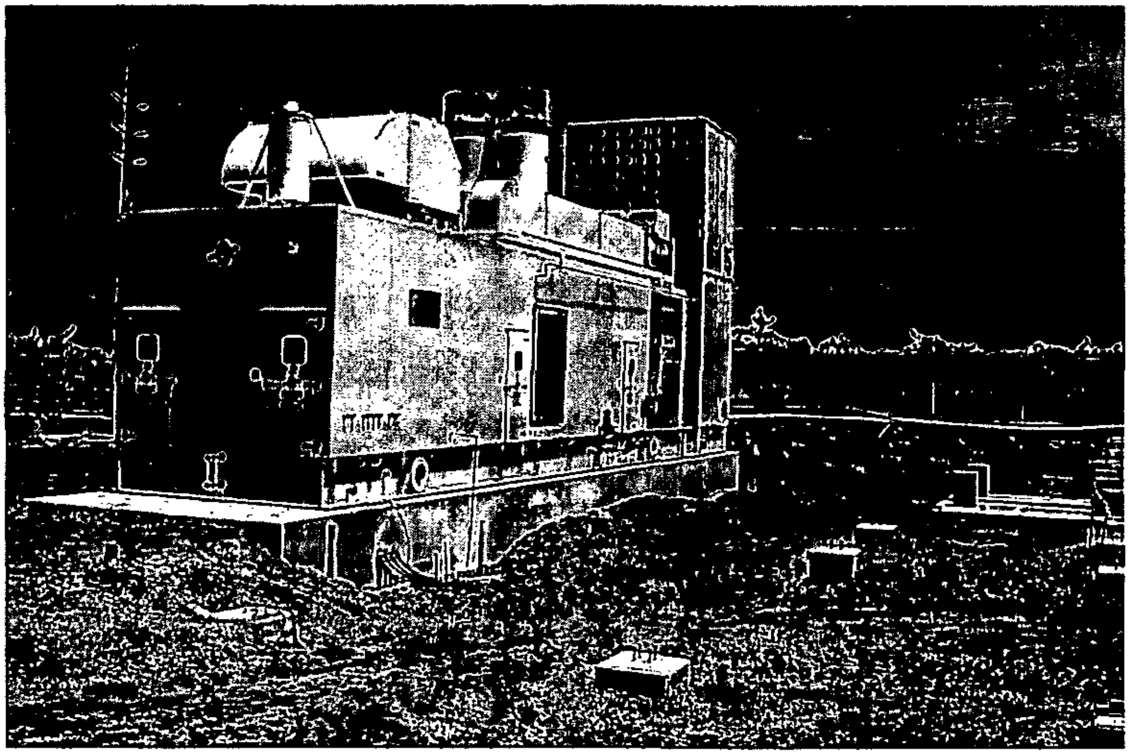
INTERIOR VIEW OF COMBUSTION TURBINE EXHAUST HOT-GAS SILENCER SHELL BEING ASSEMBLED IN THE FIELD.



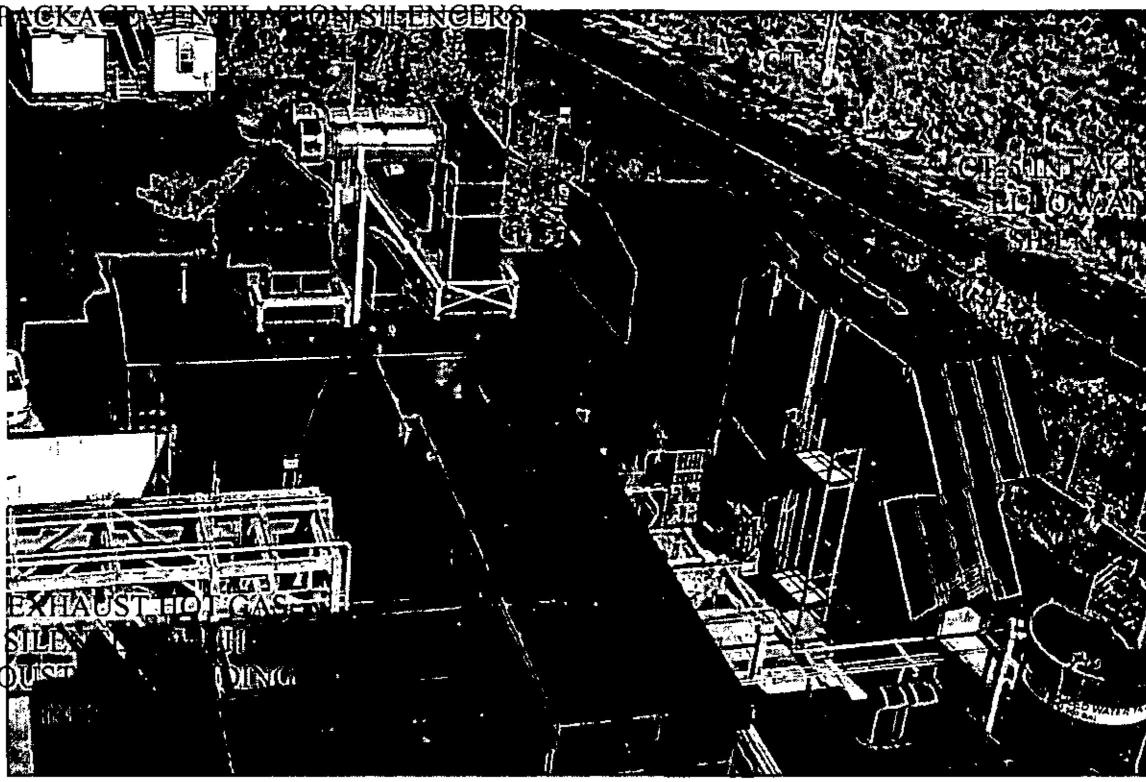
ASSEMBLED COMBUSTION TURBINE EXHAUST HOT-GAS SILENCER BEING HOISTED INTO POSITION.



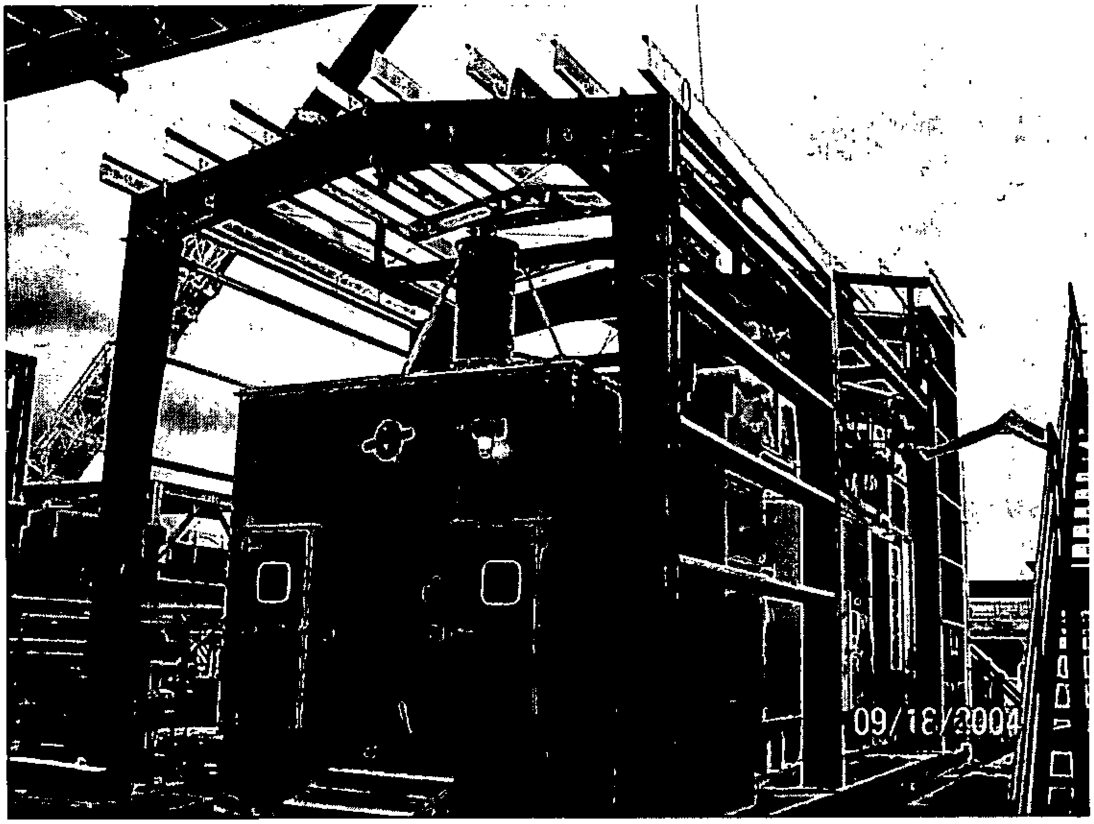
FIELD ASSEMBLY OF EXTERIOR SHELL FOR COMBUSTION TURBINE EXHAUST BYPASS SILENCER.



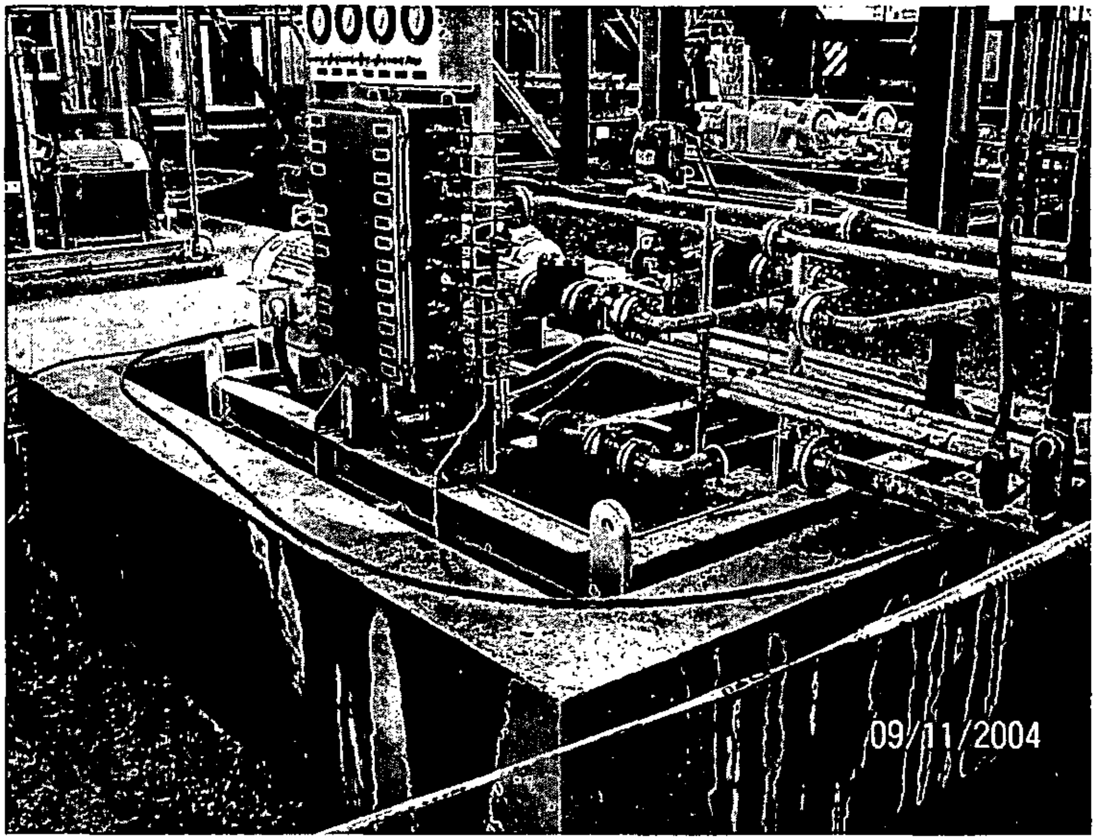
UNIT CT-5 STEWART & STEVENSON PACKAGE, PRIOR TO ASSEMBLY OF EXHAUST SYSTEM OR NOISE ABATEMENT RETROFIT.



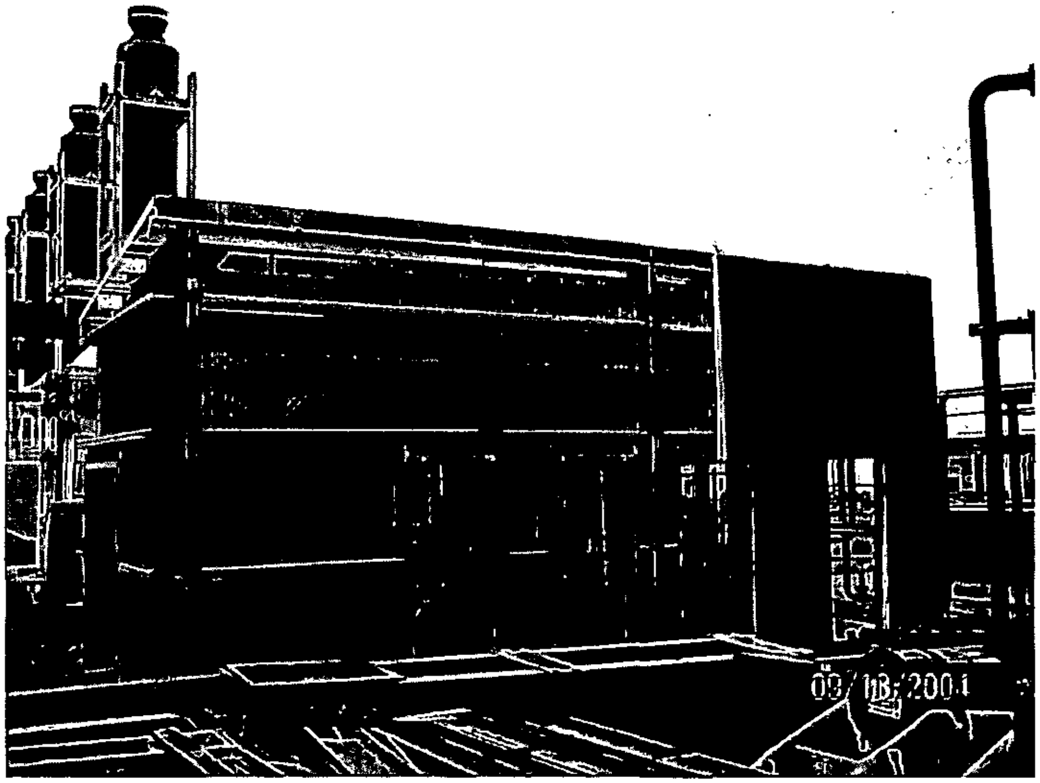
OVERHEAD VIEW OF UNIT CT-5 FOLLOWING RETROFIT OF NOISE MITIGATION MATERIALS AND EQUIPMENT.



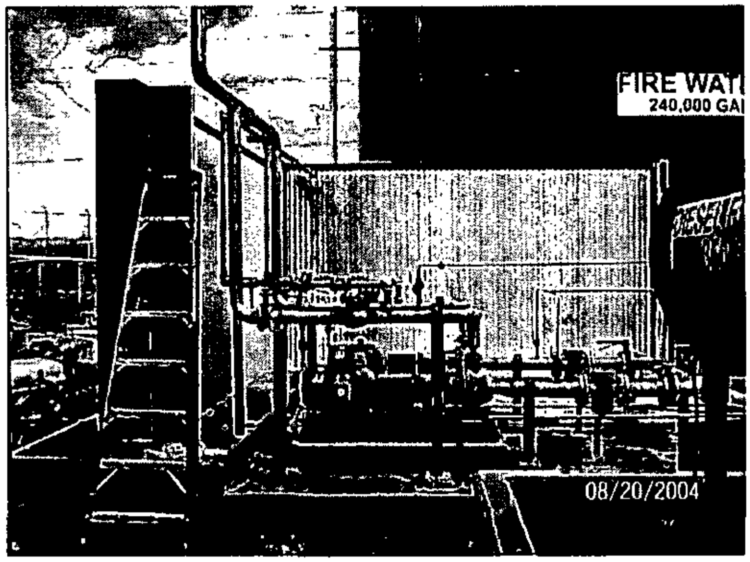
FRAMING FOR SECONDARY ACOUSTIC ENCLOSURE, BEING ERECTED AROUND CT-4.



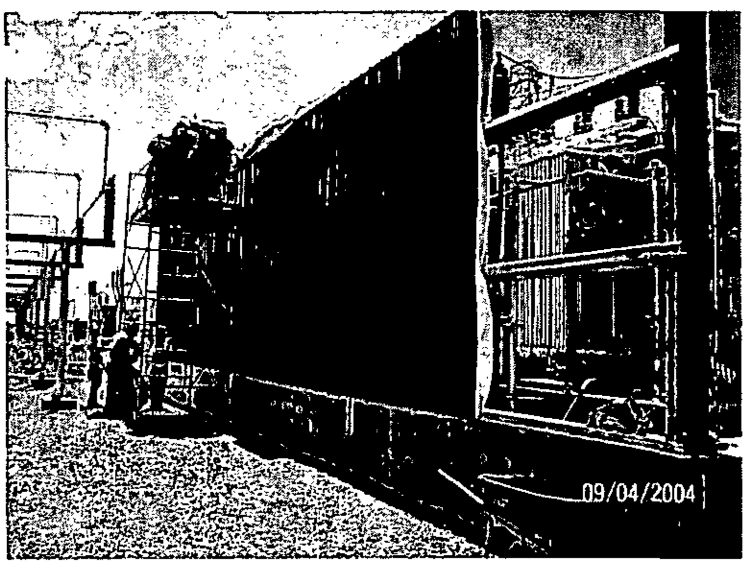
FOUNDATION IN PLACE FOR SECONDARY ACOUSTIC
ENCLOSURE AROUND CT-4 FUEL FORWARDING PUMP SKID.



FRAMING, INTERIOR AND EXTERIOR SKIN FOR SECONDARY ENCLOSURE BEING ERECTED AROUND FUEL CENTRIFUGE SKID. EMD DIESEL EXHAUST SILENCERS ARE IN UPPER LEFT BACKGROUND.



NOISE BARRIERS FOR RAW WATER PUMPS (ABOVE) AND MAIN STEP-UP TRANSFORMERS (BELOW).



CT-4 PACKAGE VENTILATION SILENCERS

CT-4 INTAKE AIR SILENCER

EXHAUST HOT GAS SILENCER

F.O. CENTRIFUGE ENCLOSURE

EXHAUST BYPASS SILENCER

KEAHOLE NOISE ABATEMENT CONSTRUCTION—PANORAMA VIEW

HELCO

KEAHOLE CT-4 & CT-5

NOISE ABATEMENT CONSTRUCTION COSTS

	CT-4 & CT-5 Acoustic Mat'ls:
1.	Air intake silencing
2.	CT package secondary enclosure
3.	CT package ventilation silencers
4.	Exhaust silencers
5.	Exhaust system shrouds
6.	Lube oil cooler silencing
7.	Water injection skid silencing
8.	FO pump skid silencing
9.	Main transformer barrier
10.	Finish painting
11.	FO centrifuge enclosure
12.	Redundant ventilation fans
13.	Raw water pump barrier
14.	Vent fan motor starters
15.	Exterior lighting
16.	CT-5 air intake elbow
17.	Equipment access features
18.	Equipment coating change
19.	Compressor cooling enclosure
20.	Add'l support steel

Noise abatement equipment that required each unit to be shut down for retrofit included items 1, 3, 4, 5, 9 and 16 from the listing of CT-4 & CT-5 acoustic materials. These are primarily items in the air intakes, exhaust gas path, and around the main step-up transformers. All of the other equipment could be built around the CT-4 & CT-5 equipment while it was operating.

Staging the noise abatement work following commercial operation of CT-4 & CT-5 brought essential generation assets on-line, but at the cost of some duplication of construction efforts.

The construction of the CT-4 & CT-5 noise abatement equipment was performed on a time-and-material basis, with numerous activities occurring simultaneously. It is therefore difficult to identify the exact level of labor and equipment resources that were expended to disassemble the CT air inlet structures and exhaust ducting, and then retrofit the new air inlet silencers, exhaust gas silencers and shrouding, and CT package ventilation equipment (acoustic materials items 1, 3, 4 & 16. Items 5 & 9 only required unit shutdown for electrical and high-temperature safety reasons and did not involve any duplication of previously-completed construction work).

The work required to install acoustic materials items 1, 3, 4, & 16 are very similar to contractor T.Bailey's work scope to originally furnish and erect the CT-4 & CT-5 exhaust bypass duct, and to erect the "Universal"-brand exhaust silencer supplied by Stewart & Stevenson. From T.Bailey's Construction Services Contract No. HWA03015 breakdown:

CT-4 Furnish Bypass Duct Material incl. Blanking Plate	$174,300
CT-4 Fabricate Bypass Duct Materials	$244,222
CT-5 Furnish Bypass Duct Material incl. Blanking Plate	$174,300
CT-5 Fabricate Bypass Duct Materials	$244,222
MAT'LS & FACTORY FAB. COST:	$837,044
CT-4 Erect Bypass Duct and Silencer	$ 41,500
CT-5 Erect Bypass Duct and Silencer	$ 41,500
ERECTION COST:	$ 83,000

RATIO:	Erection Cost	=	$ 83,000	=	0.09916	=	10%
	Mat'ls & Factory Fab. Cost		$837,044				

Erection cost for this type of equipment is about 10% of the materials and factory fabrication cost. Applying this to the CT-4 & CT-5 acoustic materials items 1, 3, 4, & 16:

	CT-4 & CT-5 Acoustic Mat'ls:		Cost:
1.	Intake air silencing		$ 228,662
3.	CT package ventilation silencers		$ 169,837
4.	Exhaust silencers		$ 812,027
18.	CT-5 air intake elbow		$ 361,106
			$1,571,632

Applying 10% factor from similar T.Bailey construction breakdown:

CT-4 & CT-5 Acoustic Mat'ls Items 1, 3, 4, 18 Erection = (10%) x ($1,571,632)	
=	$157,163

$157,163 is the estimated cost to erect CT-4 & CT-5 Acoustic Materials items 1, 3, 4, & 16. Assuming half as much again for the removal efforts is considered conservative; the old exhaust ductwork and "Universal"-brand exhaust silencers were scrapped and little care was taken in their removal. Portions of the CT-4 & CT-5 air intakes were re-used though and care was taken in their disassembly.

Erection:	=	$ 157,163
Removal:	=	$ 78,582
		$ 235,745

$235,745 is the estimated duplication of construction efforts due to sequencing the noise abatement retrofit after CT-4 & CT-5 were made commercial without acoustic treatment.

GFP 03/17/2007

REBUTTAL TESTIMONY OF
ANTHONY H. KOYAMATSU

DIRECTOR
PURCHASING - SUPPORT SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Keahole CT-4 and
CT-5 Construction

INTRODUCTION

Q. Please state your name and business address.

A. My name is Anthony H. Koyamatsu and my business address is 820 Ward Avenue, Honolulu, Hawaii, 96814. My resume is attached as HELCO RT-15F00.

Q. By whom are you employed and in what capacity?

A. I am the Director of Purchasing in the Support Services Department at Hawaiian Electric Company, Inc. ("HECO"). I am submitting testimony on behalf of Hawaii Electric Light Company, Inc. ("HELCO").

Q. What will your rebuttal testimony cover?

A. My testimony will cover HELCO's:

1) Urgency to construct CT-4 and CT-5;
2) construction activities in 2002, 2003, and 2004; and
3) reasons for added construction costs.

Q. What is your involvement in the Keahole CT-4 and CT-5 project?

A. I was the Keahole Project Manager from November 2000 to May 2004.

URGENCY TO CONSTRUCT CT-4 AND CT-5

Q. What has been HELCO's approach to installing CT-4 and CT-5?

A. As stated in Mr. Jose Dizon's testimony, HELCO RT-4A, from the start of the Keahole CT-4 and CT-5 project in 1991, HELCO acted as expeditiously as possible to obtain the needed permits and equipment to complete the installation of CT-4 and CT-5 for the purpose of adding much needed additional generation on the Big Island.

Q. Has the Commission shared the urgency of installing additional generation?

A. Yes, as is indicated in Mr. Warren Lee's testimony, HELCO RT-1, Mr. Dizon's testimony, HELCO RT-4A, and Ms. Lisa Giang's testimony, HELCO RT-4.

Q. How have Big Island independent power producers contributed to the need to construct CT-4 and CT-5 as expeditiously as possible?

A. Ms. Lisa Giang's testimony, HELCO RT-4, explains the impact the Big Island independent power producers have had on the HELCO system. Significant deratings from independent power producers Hamakua Energy Partners, L.P. ("HEP") and Puna Geothermal Venture ("PGV") have not been uncommon. For example, as stated in both Mr. Jose Dizon's and Ms. Lisa Giang's testimonies, PGV has a history of having frequent difficulties in providing the 30 MW of contracted capacity. Accordingly, HELCO had to factor the uncertainty of independent power producers into its plans to restart construction in November 2003.

As stated in Ms. Lisa Giang's testimony, HELCO RT-4, HELCO accelerated construction of CT-4 and CT-5 in early 2004 to provide reasonable assurance that CT-4 and CT-5 could be completed or substantially completed by May 30, 2004, which was the deadline to issue Hilo Coast Power Company ("HCPC") a written notice for termination on January 1, 2005. HELCO issued the written notice of termination to HCPC on May 27, 2004. By that date, CT-4 was commercially operable and HELCO had reasonable assurance that CT-5 would be in commercial operation within a few weeks. The dates for start-up testing and commercial operation of CT-4 and CT-5 are detailed later in this testimony.

Therefore, as stated in HELCO's September 7, 2005 Keahole CT-4 and CT-5 Cost Report, when construction of CT-4 and CT-5 was allowed to resume in November 2003, HELCO decided to accelerate construction activities in order to complete the installation of the major equipment by the end of 2004. HELCO's objective was to install CT-4 and CT-5 as expeditiously as possible to facilitate operating its system with adequate generation capacity and minimize the risk of generation shortfalls.

Q. Were there other factors that influenced HELCO's decision to construct CT-4 and CT-5 as expeditiously as possible?

A. The potential for further delays as a result of opposition initiated lawsuits and petitions contributed to HELCO's decision to accelerate construction. As stated in HELCO's September 7, 2005 Cost Report, the installation of CT-4 and CT-5 was significantly delayed as a result of delays in obtaining certain approvals and because of the numerous lawsuits and administrative proceedings initiated by or on account of project opponents. For example, installation of CT-4 and CT-5 was again halted in 2002, with numerous court proceedings with project opponents pending and unresolved. Fortunately, the parties that opposed the Keahole power plant expansion project (other than Waimana, which did not participate in the settlement discussions and opposed the settlement) engaged in a court-ordered mediation process with HELCO and several Hawaii regulatory agencies in an attempt to achieve a resolution of the matters in dispute that would permit the project to be constructed and put in service. Eventually, a Settlement Agreement was executed by HELCO, KDC, Ratliff, Cooper, DHHL, DOH, BLNR and DLNR, permitting HELCO to proceed with installation of CT-4 and CT-5.

In addition, as stated in Ms. Lisa Giang's testimony, HELCO RT-4, HELCO accelerated construction of CT-4 and CT-5 to avoid the possibility of another interruption, as opponents such as Waimana continued to pursue ways to block the installation of the units. At the time, it was conceivable that had the project not been accelerated, HELCO might have to halt a project that was 95% or 99% complete.

Therefore, HELCO had reason to accelerate the installations of CT-4 and CT-5 and to complete the installations as soon as practicable in order to avoid additional delays in installing needed generation in West Hawaii from potential legal actions by opponents.

Q. What was HELCO's construction strategy in dealing with the urgency to complete construction and the frequent construction stoppages?

A. As early as 1998, when HELCO's construction at Keahole was first interrupted, HELCO made preparations to be in a 'ready stand-by' mode to resume and complete construction as soon as the necessary air permit and land use approvals were obtained. For example, in periods when construction was stopped, HELCO took steps to ensure contractors were ready to remobilize at a moment's notice. Contractors, consulting engineers, construction managers, and equipment suppliers were kept updated on the latest developments with the permitting.

Further, HELCO took necessary steps to keep its construction permits and other agency approvals active, such as, County building, electrical, and plumbing permits, County water supply commitments, CDUP approvals, PSD air permit, State underground injection control permit, Community noise permit for construction activities, NPDES permits, Federal Aviation Administration permit for exhaust stack, etc.

In addition, to ensure equipment and material would be ready to install and function properly after installation, HELCO inspected, assessed, and tested equipment and materials during construction down times. Extensive efforts were also made to preserve equipment and material, as described in later sections of this testimony.

For example, HELCO positioned itself to expedite completing construction by obtaining approval for and performing Pre-PSD construction, as stated in Mr. Barry Nakamoto's testimony, HELCO RT-15C.

CONSTRUCTION ACTIVITY

Q. What construction activity ensued when construction was allowed to resume?

A. As stated in HELCO's September 7, 2005 Cost Report, when construction of CT-4 and CT-5 was allowed to resume on April 30, 2002, HELCO immediately remobilized contractors and its construction management team to recommence construction. As early as May 2002, HELCO's contractor, Scott Company of California, constructed a concrete foundation for an oil water separator. By June 2002, HELCO had two contractors, Isemoto Contracting Company and Scott Company on-site and engaged in construction activity. By the time HELCO was ordered to stop construction in September 2002, four of five prime project contractors and three sub-contractors, were on-site, actively constructing and completing portions of the plant.

Similarly, as stated in HELCO's September 7, 2005 Cost Report, when construction of CT-4 and CT-5 was allowed to resume on November 17, 2003, HELCO decided to accelerate construction activities in order to complete the installation of the major equipment by the end of 2004. Within a few weeks, HELCO had three of its five prime project contractors, along with its construction management team, on-site. On December 1, 2003, Isemoto Contracting was fully engaged in construction, pouring a concrete foundation for a fuel day-tank. Within a few months of resuming construction, HELCO was able to start-up CT-4 (first fires in March 2004) and CT-5 (first fires in June 2004).

Q. What were the dates of the key milestones relating to start-up testing and commercial operation of CT-4 and CT-5?

A. The following are the dates of the key milestones for CT-4 and CT-5, relating to start-up testing and achieving commercial operation status:

CT-4 first fire date: March 18, 2004
CT-4 first synchronized to grid: March 22, 2004
CT-4 first reached full-load: March 26, 2004
CT-4 declared commercially operable: May 25, 2004
CT-5 first fire date: June 1, 2004
CT-5 first synchronized to grid: June 2, 2004
CT-5 first reached full-load: June 7, 2004
CT-5 declared commercially operable: June 30, 2004

REASONS FOR ADDED CONSTRUCTION COSTS

Q. What reasons contributed towards construction costs being higher than the amounts originally estimated in the Commission applications?

A. As stated in HELCO's September 7, 2005 Cost Report, construction for CT-4 and CT-5 was originally scheduled to be completed in 1994 and 1996, respectively. Due to unanticipated delays, construction of the project began in 1997 with pre-PSD construction with CT-4 being placed into commercial operation in May 2004 and CT-5 placed into service in June 2004. The additional starts and stops of actual field construction added to the project cost.

Construction for CT-4 and CT-5 was originally envisioned to follow typical construction projects, where a construction completion date is established and the construction plan is then developed, with cost and schedule control as the primary emphasis. Construction cost estimates were developed for HELCO's CT-4 and CT-5 projects, using actual costs and task durations experienced from construction of almost identical generating units on Maui and in Hilo. The original technical, cost and schedule goals were reasonable and well defined. However, unplanned delays and changes in the construction schedule occurred, which were not anticipated, planned, or budgeted within the construction contracts. Since every situation that affects construction plans or schedules is unique, new plans needed to be developed to address and resolve the specific issues at the time. Accordingly, construction for the Keahole project did not follow a typical construction plan or process because of the multiple starts and stops of the actual construction.

The following provides an explanation for the reasons for the higher than originally estimated construction costs. The additional costs listed below total $6.64 million.

1. <u>ESCALATION</u>

   A. The total additional cost attributable to escalation is approximately $2.21 million.

   B. As stated in HELCO's response to CA-IR-507, HELCO experienced three separate instances (in 1998, 2000, and 2002) where construction was stopped because of a court imposed stay (or a notice of violation, as Mr. Barry Nakamoto discusses in HELCO RT-15C). As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred additional costs from escalation in labor costs, increased equipment rental, housing costs for contractors and consultants, and higher contractor-supplied materials between the construction time assumed in the original Commission application estimate and when the actual construction took place and was completed in 2004.

C. Construction in Hawaii underwent a strong upswing starting in 1998; HELCO experienced particular difficulty finding licensed contractors available to work during the 2003/2004 construction portion of the Keahole Power Plant, due to a sharp rise in construction projects along the Kona coast and in Hawaii. During this same time period steel prices dramatically increased, and steel products were difficult to obtain. Fortunately, HELCO already had on-hand most of the major equipment, piping, and components necessary to construct the plant.

D. HELCO's $2.21 million in escalation costs is validated by escalating construction costs from 1994 to the 2004 project completion date, which yields approximately $3.2 million in increased cost using trends of construction costs for the Pacific region (Handy-Whitman Index of Public *Utility Construction Costs, Bulletin No. 161, 1912 to January 1, 2005)*, for combustion turbogenerator plants construction. Similarly, using U.S. Army Corps of Engineers Civil Works Construction Cost Index System data for power plants in the Pacific region further validates an estimated construction escalation of approximately $2.7 million.

E. Alternatively, terminating existing construction contracts and re-bidding the contracts for the remaining work was considered; however, HELCO wanted to avoid switching contractors and losing the site and job specific knowledge gained by contractors who initially performed the work. In addition, establishing new contracts would have resulted in higher project costs, due to changes in the local construction environment, and could have resulted in contractors adding higher contingency margins to their proposals if they were allowed to re-bid. Instead, HELCO enforced the "Suspension" and

"Resume Suspended Work" provisions of the commercial contracts, and negotiated cost increases for labor, per-diem, materials, expenses and equipment rental for the balance of work remaining on each contract. Moreover, HELCO believed its pending permit approvals were imminent and the process of re-bidding contracts could result in additional delays. As stated herein, HELCO's strategy was to be in 'ready stand-by' mode once given the opportunity to resume construction.

2. REMOBILIZATION AND DEMOBILIZATION COSTS

A. As stated in HELCO's September 7, 2005 Cost Report, remobilization ("remob") and demobilization ("demob") of contractors accounted for approximately $1.0 million in additional costs that occurred as a result of the work stoppages mentioned herein. There were additional costs for transportation costs for equipment and personnel, pack-up costs, cleanup costs, and set-up costs borne by the contractors. These remob/demob costs were incurred after the initial construction mobilization in 1997 and demobilization in 1998. A second remob/demob occurred in 2002, and the third remob/demob happened in 2003/2004.

B. The alternative of not promptly demobilizing contractors was never considered. In each work stoppage, HELCO did not know when construction would resume, so HELCO took prudent measures to promptly demob contractors to avoid additional costs of having stagnant contractors on-site. Similarly, prompt remob ensured construction resumed as quickly as possible.

3. <u>ACCELERATION OF CONSTRUCTION ACTIVITIES</u>

A. As noted herein, time was always of the essence for HELCO. The Big Island's acute generation needs prompted HELCO to take the necessary steps to have the next generating unit on line as quickly as possible. Accordingly, as stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.65 million in additional costs to accelerate the construction portion of the project. As discussed earlier in my testimony, when construction of CT-4 and CT-5 was allowed to resume in November 2003, HELCO decided to accelerate construction activities in order to complete the installation of the major equipment by mid-2004.

B. The alternative of not accelerating construction would have delayed completion of the units and contributed to the risk of further generation shortfalls. Furthermore, had construction not been allowed to resume in 2004 and/or construction was not accelerated, factors such as escalation and contractor labor availability would have further increased project costs.

4. <u>EQUIPMENT UPKEEP AND TEMPORARY SAFETY MEASURES</u>

A. As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.84 million in additional costs to install and maintain temporary measures to safeguard structures and equipment that were partially erected at the time of the construction work stoppages.

B. Alternatively, failure to take these measures would have resulted in ruined work and equipment, potential additional delays to replace damaged equipment, and placing HELCO's site personnel at risk from hazards such as open excavations, unguarded electrical connections and unlit areas.

5. EQUIPMENT AND MATERIAL RETESTING, REPLACEMENT, AND RESTORATION COSTS

   A. As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.56 million in additional construction contractor costs to upkeep and inspect, test, rehabilitate, repair or replace, and upgrade equipment and material that were purchased and then kept in storage because of delays in construction. HELCO implemented measures to preserve the property while in storage, utilizing indoor warehouse facilities where available, supplying weather and ultraviolet protection, energizing space heaters and panel heaters to prevent moisture build-up, blanketing equipment and pressure vessel interiors with inert gas to address corrosion attack, rotating idle machinery shafts by hand to prevent brinnelling of bearing surfaces, and performing periodic inspections including partial disassembly of some machinery. However, because of the age and condition of the equipment after the long storage durations, additional efforts were still necessary to troubleshoot, start-up, and resolve equipment degradation due to storage after the multiple project starts and stops.

   B. Alternatively, failure to repair, replace, or restore equipment and material would have ultimately resulted in either an unsuccessful plant start-up and/or the premature failure of components or systems.

6. CHANGES IN PERMITTING REGULATIONS, CODES, AND ADDITIONAL INSURANCE REQUIREMENTS

   A. As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.45 million in additional costs because of actions taken in response to changes in codes, regulations, and insurance requirements that occurred during the project's duration. For example, in November 2002, Hawaii promulgated new state crane certification regulations that became effective in October 2003. Construction contracts, dating back to the late-1990s, needed to be revised to reflect these new safety requirements, and the added cost was at a premium due to the shortage of certified machinery in Hawaii with properly licensed operators.

B. Alternatively, failure to comply with the subject changes would have resulted in fines or penalties against HELCO, as well as possibly further delays.

7. RESTART ACTIVITIES

A. The total additional cost attributable to restart activities is approximately $0.47 million.

B. As stated in HELCO's September 7, 2005 Cost Report, for each major delay in the project, HELCO incurred additional costs to restart the project and the ongoing activities, beyond physically mobilizing personnel and equipment to the site. Additional costs were incurred for engineers, project management personnel, construction management personnel, and contractors, many of whom were new due to the long delays, to become familiar with the project after the long delays. Costs were also incurred to inventory materials, assess equipment condition, and to renegotiate contracts.

C. The alternative of not performing the fore mentioned restart activities would have resulted in significant delays in completing CT-4 and CT-5, as well as additional cost and risk.

8. STORAGE OF MATERIALS

A. As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.23 million in additional costs because of additional contractor costs to store equipment and materials, transport or re-transport if required, rental fees for contractors to retain equipment during work stoppage periods, and in some cases purchase of material racks and cribbing to avoid demurrage charges due to the long work stoppage periods.

B. Alternatively, failure to take necessary steps to properly store equipment and materials would have resulted in premature deterioration and additional cost to replace equipment and materials.

9. <u>DESIGN CHANGES TO IMPROVE OPERATIONAL RELIABILITY AND SAFETY</u>

A. As stated in HELCO's September 7, 2005 Cost Report, HELCO incurred approximately $0.23 million in additional costs as a result of changes in design to improve operational reliability and safety. Examples include installation of a multi-unit fuel centrifuge to remove salts and impurities from the fuel to prevent corrosion in the hot gas regions of the combustion turbines; additional SCADA interface to provide remote operation of CT-4 and CT-5 for improved reliability; upgrading the demineralizer controls and components to allow single train operation to provide operational flexibility and improve reliability; and installation of a fiber optic local area network service/connection to improve communication speeds for improved reliability, and other improvements.

B. The construction management and start-up personnel expended significant efforts troubleshooting and resolving numerous and unexpected equipment failures. Some examples of failed devices included the electronic circuit boards for the combustion turbine governor control system, electronic components of the distributed control system, gasket failures throughout the combustion turbine and associated equipment, and failures of electro-mechanical devices such as fuel flow meters, circuit breakers, and switchgear. Addressing these issues delayed start-up by 1 to 2 months.

C. The long-term storage of the combustion turbines (since 1995) made it prudent to conduct portions of the factory acceptance testing on-site for safety and reliability reasons. Conducting portions of the factory acceptance testing required specialized equipment, original equipment manufacturer personnel, and approximately three weeks of additional dedicated testing support by the construction management and start-up teams.

D. HELCO offset much of the costs for design revisions by reducing the scope of the project. This included removing restroom facilities, plumbing, and septic system from the water treatment building, deleting pavements and parking lots, removing the fire pump building, and changing the design of the Control Building and Shop/Warehouse Building to pre-engineered buildings. As a result of these credits, design revisions accounted for about $228,000 in added costs to the construction portion of the project.

E. Alternatively, failure to implement these design changes would have resulted in significant additional cost and risk as mentioned above.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes it does.

Hawaiian Electric Company, Inc.

ANTHONY H. KOYAMATSU, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 820 Ward Avenue P. O. Box 2750 Honolulu, HI 96840
Position:	Director of Purchasing Support Services Department
Education:	Bachelor of Science in Mechanical Engineering with Distinction University of Hawaii, 1985
Other Qualifications:	Licensed Professional Engineer State of Hawaii, Mechanical Branch - 1994
Experience:	HAWAIIAN ELECTRIC COMPANY, INC.
	2004 - present Director of Purchasing Support Services Department Hawaiian Electric Company, Inc.
	2000 - 2004 Project Manager, Power Supply Engineering Department, Hawaiian Electric Company, Inc.
	2000 Shift Supervisor, Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc.
	1998-2000 Year 2000 Associate Project Manager, Information Systems Department, Hawaiian Electric Company, Inc.

Experience (cont'd):	1996 - 1998 Operating Engineer, Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc.
	1991 - 1996 Betterment Engineer, Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc.
	1985 - 1991 Project Engineer Naval Ocean Systems Center, Department of the Navy
Other Curriculum:	Corporate Training Course

REBUTTAL TESTIMONY OF
R. BEN TSUKAZAKI

CONSULTANT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: KEAHOLE LAND USE

INTRODUCTION

Q. Please state your name and business address.

A. My name is Robert Ben Tsukazaki. My business address is 85 West Lanikaula Street, Hilo, Hawaii 96720.

Q. What is your occupation?

A. I am an attorney and primarily practice in the subject area of real estate law, concentrating in land use law.

Q. How long have you practiced land use law?

A. Of the thirty years or so of being an attorney, I have been involved in land use matters for 28 years or so. Five of those years involved the practice of land use law in the public sector as a Deputy Corporation Counsel for the County of Hawaii. My professional biography is attached hereto as "HELCO-R-15F00."

Q. Please describe your involvement with the subject docket.

A. I have been asked by HELCO to review the land use issues in the pending PUC proceeding.

CDUA VERSUS RECLASSIFICATION/REZONING

Q. Have you reviewed the Keahole Defense Coalition ("KDC") position statement and the documents filed by the Consumer Advocate?

A. Yes, to the extent that they address land use issues relating to HELCO's pursuit of a conservation district use permit ("CDUP") via a conservation district use application ("CDUA") in 1992.

Q. What is your understanding of the land permits already in place for the Keahole plant as of 1992?

A. I am aware that an initial CDUP was granted in 1973 and was amended a number of times subsequent to that grant.

Q. *What is your understanding of the further land entitlements required in order for HELCO to pursue expansion of the plant?*

A. My understanding is that HELCO needed another development approval in order to expand its plant and that the two available procedures for such an approval were the CDUA and another process that involves a State land use district reclassification that is followed by a county rezoning action. Other related permits are required, such as an air permit, as well as permits that are of a ministerial nature, such as a building permit, grading permit, and so on.

Q. KDC, at pages 19-20 of its Position Statement, claims that HELCO could have avoided the problems and delays that occurred in the land permitting process if it had pursued reclassification and rezoning rather than an amendment to its CDUP. Are you familiar with both the CDUA and land use district reclassification and rezoning processes?

A. Yes, I am familiar with the CDUA process and the process that I'll refer to as the "Reclassification/Rezoning" process, which really consists of two separate processes: one at the State level (through the Land Use Commission) ("LUC") to reclassify a State land use district, and the other at the county level (ultimately through the County Council) for a change in the county zoning district.

Q. Please describe the processes for the CDUA and the Reclassification/Rezoning alternatives circa 1992.

A. The CDUA process is a quasi-judicial process that is administered by the Department of Land and Natural Resources ("DLNR") through the Board of Land and Natural Resources ("BLNR"). The BLNR's rules provide the substantive and procedural requirements for the consideration of and action on a CDUA. The CDUA process is intended to allow a landowner to request an approval for the implementation of a land use within the conservation district. The CDUA process requires a discretionary action by BLNR, based upon its consideration of criteria that are set forth in its rules. Any approval is subject to conditions subsequent in the interest of the public health and welfare. Pursuant to §183C-6(b), Hawaii Revised Statutes, ("HRS"), BLNR is required to act on a CDUA within 180 days of its official filing date, which may be extended at the applicant's request. At all relevant times in this matter, a concurring vote of at least four BLNR members was required for a valid action. Under such statutory provision, a failure of BLNR to act within such period results in an automatic approval of the CDUA, i.e., a "default entitlement." Under BLNR rules, a contested case procedure can be invoked by a person or entity that is found to have standing to be a party. In such case, the ultimate BLNR action on a CDUA may be appealed to the circuit court for judicial review by such party to the contested case.

Q. Please describe the CDUA process?

A. In the CDUA process, the BLNR has discretion to approve CDUAs and impose conditions upon them. The process can be subject to a contested case procedure and an appeal may be taken on the BLNR's ultimate decision.

Q. KDC asserts that it was imprudent for HELCO to decide to seek a land use entitlement by means of the CDUA process in 1992. Do you agree?

A. No, I do not agree with that position. While the CDUA approval process can, on occasion, involve certain obstacles, it must be noted that HELCO's 1992 CDUA did not seek approval to introduce a new land use on property that was undeveloped for that purpose, which often results in significant opposition to a project. Instead, HELCO was in fact proposing an amendment of a 1973 CDUA approval (an existing CDUP) that previously permitted power generating facilities at the Keahole site. Subsequently, other amendments to the CDUP were granted in 1984, 1987, and 1988, allowing the installation of additional facilities and improvements. Thus, the 1992 CDUA simply proposed another amendment in a line of amendments that allowed further development of the Keahole site as a regional power generation plant for West Hawaii. Accordingly, it is reasonable to conclude that, given the history of prior entitlements, the CDUA process probably was the more prudent process to use in seeking approval of additional facilities that had been previously approved by the CDUP and amendments thereto.

Q. Please describe the process that you refer to as the "Reclassification/Rezoning" process.

A. The Reclassification/Rezoning process initially involves the LUC procedure for petitions for district reclassifications (also referred to as "district less boundary amendments"). Pursuant to the LUC's rules, which prescribe a contested case hearing procedure, a hearing must be conducted on the island on which the subject property is situated not less than 60 days and not more than 180 days after a filing has been deemed complete.

In 1992 and up to 1998, there was no mandatory period within which the LUC was required to decide whether to grant or deny a petition for district reclassification. Therefore, at the time that HELCO was considering how to obtain its entitlements for the Keahole plant expansion, there were no mandatory time limits for LUC action, and thus, a total time frame for the LUC process could only be estimated. Exclusive of any time required for technical and consultant studies, the preparation of reports, compliance with Chapter 343, HRS (generally requiring the preparation of an Environmental Impact Statement or "EIS"), and the preparation of the petition and necessary exhibits, the LUC process could be generally expected to take from one to three years, after an application has been accepted as complete (including acceptance of the EIS), depending on the level of controversy surrounding the case.

Based on my experience, LUC proceedings in the 1980s and early to mid-1990s occasionally took two to three years. I was involved in proceedings of such duration. A vote of at least six (of the nine-member LUC) is required in order for a reclassification petition to be validly approved. Approvals are subject to conditions in the interest of the public health and welfare.

Since 1998, the LUC has been required to act on a petition within 365 days of the filing being deemed complete, unless a written motion for extension of time is approved. A failure to act within such period results in the automatic approval of a petition.

Q. Are there risks associated with the LUC reclassification process beyond the time considerations already discussed?

A. Yes. As with the CDUA process, a contested case hearing procedure is available to allow project opponents a formal opportunity to participate in a hearing with all of the procedural rights provided under Chapter 91, HRS. As with the CDUA process, there is the additional risk that conditions of approval may be imposed. As with the grant of a CDUP, an LUC approval can be appealed under Chapter 91. In the case of Kaupulehu Developments, LUC Docket No. A93-701, the combined time taken for the LUC proceeding (initiated in 1993), an appeal taken therefrom, a remand resulting therefrom, and the LUC proceeding on remand was ten years.

Q. What factors could have affected the time to process a 1992 application for reclassification with the LUC? What types of additional delays or complications could have arisen in that process? Can you provide examples?

A. Generally, I would say that the magnitude of delays or complications is dependent on the constitution and positions of the respective parties to the LUC proceeding. Statutorily-mandated parties to a reclassification proceeding are a county's planning department and the State planning office (now known as "Office of Planning"). In addition, as described above, the contested case procedure affords an opportunity for individuals or groups who meet the LUC's standing criteria to intervene as parties.

In the usual case, the intervenors are represented by attorneys and oppose the proposed reclassification. Procedural delays can be caused by disputes over matters such as scheduling, the disclosure of information, the relevancy of certain issues, and even certain rulings by the presiding officer. Based on my personal experience in a 1993 case, an LUC proceeding is subject to being suspended while a party takes an interlocutory appeal to the circuit court.

Public participation through live testimony can be a time-consuming step, especially in controversial cases where public testimony can go on for multiple days and on each day of a reconvened hearing. Delays can also result when the county planning department or the Office of Planning either oppose or raise serious concerns about the reclassification. In such cases, additional information must be developed and added to the evidentiary record.

Q. Please describe the County of Hawaii rezoning process.

A. After the LUC process is completed and a district reclassification is approved by the LUC (in HELCO's case, an urban district reclassification would have been necessary for a power generating plant), the required County of Hawaii rezoning process can begin. In HELCO's case, a general industrial zoning district would have been required by the County in order for a power generating plant to be permissible.

In 1992 and up to 1996, the Hawai`i County Code provided that, once a complete rezoning application was accepted as complete by the Planning Department, the Planning Director had 240 days to forward his or her recommendation to the Planning Commission, unless the applicant agreed to a longer period. If the Director failed to make a timely recommendation, the materials were to be forwarded to the Planning Commission with a favorable recommendation. The Planning Commission was required to hold a public hearing on the application and forward its recommendation to the County Council.

There was no explicit time period during which the Planning Commission was required to act, nor was there such a time period for action after the application was forwarded to the County Council. After an amendment to the Code in 1996, the Planning Director's review period was reduced to 120 days after the acceptance of a complete application.

Once the materials have been forwarded to the Planning Commission for its review and recommendation, it has 90 days from the date of receipt to conduct and complete its public hearing(s) and to forward its recommendation to the County Council. The Council must then hold at least two full Council readings on the bill for proposed rezoning and make its decision as to whether to approve or deny the application. There is still no limitation on the time that can be taken to make this decision.

A majority vote of the nine-member Council is required for a final action on the application, the approval of which takes the form of an ordinance that effects the rezoning. It should be noted that the Hawaii County Charter provides the Mayor with the power to veto ordinances, and any such veto would stand unless overridden by the vote of six members of the County Council. Conditions are imposed in any approval in the interest of the public health and welfare. Due to the absence of any limitation on the public meeting/hearing component and any mandatory period for action by the Council, the timeframe of the entire process is uncertain.

Between 1992 and 1996, I estimate that the rezoning process after the acceptance of a completed application would have taken between 12 and 16 months to complete. After 1996, completion of the change of zone process after the acceptance of a complete application could be expected to take between 10 and 12 months if the application was not significantly controversial.

The county rezoning process is also subject to judicial review through an action challenging the validity of the ordinance. Appellate procedures are applicable and can result in several years of litigation. In the matter of the 1992 rezoning ordinance for Kohala Joint Venture for land in North Kohala, Hawaii, the combined rezoning and judicial processes endured over a period of approximately eight years.

Q. Are there other risks involved in the County's rezoning process?

A. Yes. It is important to note that, between the time of a LUC approval and a subsequent County rezoning approval, there would have been period in which HELCO might have experienced difficulty in obtaining various permits for improvements at its Keahole site. Once the property was reclassified as an urban district, it would no longer have been within the primary jurisdiction of BLNR or DLNR. However, because it would not yet have been rezoned to an industrial zoning district, it is possible that County officials would have treated the Keahole plant as a restricted, non-conforming use, rather a fully permitted use within such district.

The most obvious risks are similar to those in the CDUA process. However, the rezoning process does not involve a contested case hearing because the nature of the Planning Commission and County Council meetings or hearings is such that Chapter 91, HRS, does not apply. The Planning Commission's function in the rezoning process is advisory, not adjudicatory. The County Council's function is a legislative one. Chapter 91 does not apply to proceedings in either of those functions. The normal risks are the uncertainties of a discretionary process that technically has no end, the potential hardships in compliance with conditions of approval, and the potential for an unfavorable result and/or delay due to judicial action that challenges the validity of the rezoning ordinance. It must also be noted that the existence of the veto power of the Mayor also poses a risk that does not exist in either the CDUA or LUC reclassification processes.

Q. Please summarize the points of comparison between the CDUA and Reclassification/Rezoning processes.

A. In a summary comparison between the CDUA and Reclassification/Rezoning processes, one would reasonably conclude:

1) Both processes involve discretionary actions by the decision-making entities. However, the Reclassification/Rezoning process involves sequential processing and decision-making by two entities: the LUC and, assuming the LUC has approved the district reclassification, then the County Council. In addition to the greater time requirement needed to complete both the LUC and County processes, there is an increased risk in

that each is an unrelated discretionary process, and each will involve the imposition of conditions that inevitably affect the viability of a proposed development.

2) The CDUA process is expressly limited to a period of 180 days from the time that a completed application is accepted. The Reclassification/Rezoning processing time is technically unlimited. In 1992 and up to 1998, the LUC process was not limited by any mandatory action period. In addition, under the Hawaii County Code from 1992 to 1996 and at present, there is no maximum period in which the County Council must take action, perhaps reflecting the fact that the Council is performing a legislative function.

3) Both processes are subject to judicial review. However, whereas the CDUA approval is susceptible to one appellate process following the single discretionary action by BLNR, the Reclassification/Rezoning process is subject to such review after each discretionary action is taken (first by the LUC, followed by the County Council), thereby being subject to two separate appellate processes in two different time frames.

Q. Given your description and observation of these respective land use entitlement processes and assuming the material chronological facts in the underlying record, please provide your comments on the arguments set forth by KDC in its Position Statement that HELCO's pursuit of a CDUA in 1992 was "fast tracking" the required land use entitlement, ". . . by assuming the disadvantages of a conditional use permit [i.e., CDUA] over the advantages of rezoning." (KDC Position Statement, page 6.)

A. I see no basis for KDC's characterization. As described above, assuming similar circumstances apply, there are no inherent disadvantages that the CDUA process possesses, as compared to the Reclassification/Rezoning process. Accordingly, given the situation faced by HELCO in the 1992 timeframe, the CDUA process would not have presented any disadvantages that were not also inherent in the Reclassification/Rezoning process at that time. The CDUA process is a discretionary process in which a conditional approval may or may not be granted, similar to the Reclassification/Rezoning process. To the contrary, it may be considered to be advantageous when compared to the Reclassification/Rezoning process because:

1) its mandatory action period of 180 days is considerably better than what I would estimate to be 4-5 years of processing time in the 1992-1997 period for a sequential Reclassification/Rezoning process lacking a mandatory period for a final County decision on a rezoning application;
2) it involves a single discretionary procedure, whereas the Reclassification/Rezoning alternative involves two separate discretionary actions by two agencies from different levels of government; and
3) with regard to the risks involved in judicial review, the CDUA approval is only subject to one appellate process, while two separate appellate processes may be taken (i.e., from each of the approvals) in the Reclassification/Rezoning process. Without time limits at each level of the appeal process, judicial review can take several years.

Q. Please provide your comments on KDC's characterization of the reclassification and rezoning approvals as a "permanent entitlement" and the approval of a CDUA as a "conditional entitlement." (KDC Position Statement, paragraph "C", page 15.)

A. There is no basis for KDC's characterization of the Reclassification/Rezoning approvals as a "permanent entitlement" while characterizing the approval of a CDUA as a "conditional entitlement." As described above, all of the subject discretionary approvals are in fact conditional approvals because they are subject to conditions subsequent, which, if unfulfilled, can be a basis for nullification of the approval. Thus, the Reclassification/Rezoning approvals are inherently neither more advantageous nor more permanent than a CDUA approval. Given the dual-approval nature of the Reclassification/Rezoning process, it is also important to recognize the disadvantage that arises from each of the two approvals being subject to a distinct set of conditions, most of which can be independent of those relating to the other approval.

Q. Based on these observations and your professional experience, do you agree with the conclusions underlying KDC's assertion that HELCO's decision to undertake the CDUA process in 1992 and remain involved in that process was unreasonable and imprudent?

A. I do not agree with KDC's conclusions, based on the following:

1) While my perspective here is that of an attorney working in the field of land use law, I am also a resident of the island of Hawaii and recall the electric grid problems that arose in the late 1980s and early 1990s. In retrospectively considering the reasonableness or unreasonableness of HELCO's actions beginning in the 1992 timeframe, it is reasonable to consider the circumstances affecting the electric system at that time. Power failures and rolling blackouts were occurring due to limited power generating facilities, increases in demand, and problems inherent in a grid that covers an area that is almost twice as large as all of the other Hawaiian

islands combined. It was apparent to me at the time, and was confirmed as I reviewed the record in the Keahole matter, that HELCO was under considerable pressure from the public, the regulators and others to expand and improve its power generating facilities. This backdrop supports HELCO's decision to move forward with a CDUA or other approval process as reasonable under those circumstances.

2) The 1992 CDUA was in essence a proposed amendment of a 1973 CDUP for additional power generating facilities, which CDUP had previously been amended in 1984, 1987, and 1988.

3) Thus, given such BLNR approval of additional generation facilities at Keahole, there was a reasonable basis for HELCO to seek additional facilities through a CDUA that would amend the scope of the prior CDUP.

4) Looking at it from the perspective of the circumstances as known or reasonably projected in the 1992 timeframe, it was reasonable for HELCO to conclude that the CDUA process provided the advantages of potentially less processing time, less potential risk, and a continuity in the oversight of the expansion of what had been well-established as the local power generating plant for West Hawaii. It is also notable that, at the time of the 1992 CDUA, BLNR rules had for many years permitted industrial uses within the conservation district, subject to the securing of a CDUP.

<u>HELCO'S INVOLVEMENT IN PROCEEDINGS REGARDING ITS LAND RIGHTS</u>

Q. Do you agree with KDC's characterization of HELCO's participation in litigation and other proceedings that challenged the 1992 CDUA process and the resulting default entitlement as being unreasonable? Was there any point at which it was no longer reasonable to defend the default entitlement?

A. No, I see HELCO's participation to have been reasonable for the following reasons. Based upon the chronology of events that commenced with the filing of the 1992 CDUA, it was reasonable for HELCO to defend its procedural and substantive rights and either seek or stipulate to extensions of time and other procedural matters in order to complete the CDUA process once it had been initiated. After judicial confirmation of its default entitlement in 1997, it would have been even more reasonable for HELCO to participate in litigation that threatened to deprive HELCO of its entitlement and the property rights flowing therefrom and that would have allowed HELCO to proceed with its plant expansion.

Once litigation had commenced, it is also reasonable to conclude that neither HELCO nor any other party had matters under their sole control. In addition to the parties' litigation strategy, there is the independent factor of the judge's own understanding of the case and the broad discretion to rule as he or she saw fit. It appears to me that, in the course of the litigation and administrative proceedings, HELCO was primarily put in a position of responding to the various rulings and taking such procedural steps in court and at the agency level that were consonant with such rulings and that were necessary to protect its entitlements.

Q. Was it reasonable for HELCO to confirm, then defend, the 1996 default entitlement in the Third Circuit Court?

A. I believe that it was reasonable, if not obligatory, for HELCO to commence an action in 1996 in order to confirm its default entitlement under section 183-141, HRS, in light of the refusal of BLNR to explicitly recognize in its minute orders that HELCO had acquired rights to expand its plant pursuant to the failure of BLNR to take effective action within the mandated 180-day period.

Q. What is your understanding of the three-year construction deadline issue with regard to the project? Do you believe HELCO had a reasonable basis to conclude that the three-year deadline did not apply to the project?

A. My understanding of this issue is that the three-year construction deadline applies as a condition subsequent to a CDUP. Under the facts of HELCO's 1996 CDUA disposition, there does not appear to be a basis to apply that deadline because there was technically no CDUP granted. The failure of BLNR to timely act upon HELCO's CDUA resulted in an automatic right in HELCO to proceed with its proposed facilities. Therefore, it was reasonable for HELCO to believe that the three-year deadline was inapplicable.

A review of the record also indicates that various rulings or actions of the circuit court, DLNR, or BLNR provided HELCO with a reasonable basis to believe that the deadline did not apply, at least until the circuit court's explicit September 2000 ruling on the matter. Apparently, the hearings officer in the 2001 contested case hearing reached the same conclusion, as reflected in the findings of fact and conclusions of law in the March 2000 BLNR extension.

Q. KDC faults HELCO for bringing the 1996 declaratory judgment action to confirm its default entitlement, stating that, "By bringing its own action, the Company consumed the first 16 months of its 3-year construction period [and] left only <u>20 months</u> 'on the clock' remaining for the 3-year period." Was it reasonable for HELCO to engage in such litigation when it allegedly could have proceeded to complete the project within the three-year maximum construction period?

A. Yes. DLNR's initial refusal to process HELCO's construction drawings effectively made it impossible for HELCO to obtain County permits for the construction of its facilities. HELCO had spent two years attempting to have

DLNR process its drawings. Without bringing the declaratory judgment action in Circuit Court, HELCO would have been unable to obtain DLNR's cooperation to process the drawings and allow HELCO to obtain its building permit at the County level.

Under the applicable law and the facts which weighed heavily in favor of HELCO's entitlement to proceed, there appears to have been a necessity and more than a sufficient basis for HELCO's decision to protect its rights through litigation. It was also reasonable for HELCO to expect a favorable result in the Circuit Court, given the court's November 9, 1994 decision which recognized that BLNR, by its vote in 1994, had not taken action within the 180-day period (although the court then remanded the case to BLNR to hold a contested case hearing in order to protect the rights of certain parties).

Q. Once the Circuit Court ruled in September 2000 that the three-year deadline did apply to the project and that it had expired in April 1999, do you feel that HELCO was reasonable in attempting to obtain an extension of the construction deadline from BLNR?

A. It appears that taking such action was consonant with the court's ruling, and, in light of the actions by BLNR and the opposing parties at the administrative and judicial levels during the interim between 1996 and 1999, HELCO had an equitable argument that it had proceeded in good faith by attempting to comply with the three-year deadline, only to have DLNR refuse to process the construction plans, arguably in contravention with the court's initial decision that held that BLNR had not acted timely on the CDUA, thus effecting the automatic right to proceed on HELCO's part.

Q. Was it was reasonable for HELCO to defend the default entitlement and, later, the construction deadline issues in the Hawaii Supreme Court? Was there any point in the Supreme Court proceedings where it was no longer reasonable to defend the default entitlement?

A. As stated above, I am of the opinion that HELCO had the responsibility, if not the obligation, to defend and protect its apparent rights in litigation. The clearest indication of the reasonableness of HELCO's actions with regard to the default entitlement is that HELCO ultimately prevailed on this issue at both the Circuit Court and Hawaii Supreme Court. I believe that the chronology of facts in this case demonstrates the unfairness and troubling disregard for HELCO's rights that created significant delays and increased costs for HELCO. I also believe that an abandonment of its rights would have been unreasonable.

LEGAL FEES

Q. KDC is opposed to including in HELCO's proposed rates the amount of attorney's fees that were incurred during the CDUA process and subsequent related litigation, and the Consumer Advocate took the position that certain legal fees should be disallowed. In reviewing their positions and the fee information that was provided therein, do you consider the amount of such fees to be reasonable in light of the facts of this case?

A. I consider the amount of fees to be reasonable in light of the duration of this matter, which extended over approximately 11 to 12 years. In addition, the facts indicate multiple administrative and litigation proceedings and a complexity of issues. The record also shows a serious degree of resistance from project opponents, as well as non-action or ambiguous action by regulators. As addressed above, I believe it is reasonable for HELCO to have engaged in litigation and administrative proceedings to protect its entitlement. Retaining knowledgeable and highly skilled counsel in that regard was prudent, and the reasonableness of that decision and the costs thereof is supported by the outcome of such litigation and administrative proceedings, and, additionally, by a successfully structured settlement of the dispute with KDC and other interested parties.

CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Tsukazaki Yeh & Moore
ATTORNEYS AT LAW
A Limited Liability Law Company

85 W. Lanikaula Street Hilo, Hawaii 96720
Telephone (808) 961-0055 FAX (808) 969-1531

R. BEN TSUKAZAKI
rbt@lava.net
THOMAS L. H. YEH
tly@lava.net
MICHAEL W. MOORE
mmoore@lava.net
JAMAE K.K. KAWAUCHI
jkk@lava.net

PROFESSIONAL BIOGRAPHY OF

R. BEN TSUKAZAKI, ESQ.

Mr. Tsukazaki is an attorney whose professional career has resulted in his long-standing role as principal in the law firm of Tsukazaki Yeh & Moore ("TYM"), founded in 1987. Mr. Tsukazaki concentrates in the areas of land use, planning and administrative law.

Record of Experience

Tsukazaki Yeh & Moore, Partner - 1987 to Present

Carlsmith, Wichman, Case, Mukai & Ichiki, Associate - 1984 to 1986

County of Hawaii, Deputy Corporation Counsel for Planning Commission and Planning Department – 1979 to 1984

Education

Juris Doctor - Hastings College of Law, University of California, 1976

Bachelor of Arts - University of Hawaii, 1976

TYM has served the following clients in land use matters through Mr. Tsukazaki:

- Barnwell Industries, Inc.
- Big Island Country Club Homes, LLC
- CMI Development, Inc./ Kiilae Estates, LLC
- Doutor Coffee Co. Hawaii, Inc.
- Hawaii Island Economic Development Board
- Hokukano Ranch
- Kamehameha Investment Corp.
- Kaupulehu Makai Venture (Hualalai Resort)
- Hualalai Investors, LLC
- Kealakekua Heritage Ranch
- Keauhou Resort Development Corp.
- Kohala Ranch Development Co.
- Lanihau Properties, LLC
- Puna Geothermal Venture
- Seascape Development, LLC/Westpro Developments
- University of Hawaii at Hilo
- W.H. Shipman, Ltd.
- 1250 Oceanside Partners

Professional Registration and Associations

Member, American Bar Association

Member, Hawaii State Bar Association, Bar No. 1954

Member, Hawaii County Bar Association

REBUTTAL TESTIMONY OF
GAYLE OHASHI

DIRECTOR, FINANCIAL ANALYSIS
MANAGEMENT ACCOUNTING AND FINANCIAL SERVICES
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Gayle T. Ohashi and my business address is 900 Richards Street, Honolulu, HI 96813.

Q. By whom are you employed and in what capacity?

A. I am the Director of the Financial Analysis Division at Hawaiian Electric Company, Inc. ("HECO").

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HELCO T-16.

Q. What will be presented in this testimony?

A. My rebuttal testimony will:

1) Present the Company's rebuttal position related to the estimated average rate base for the test year 2006;

2) Compare the Company's position to that of the Consumer Advocate; and

3) Present the revised working cash calculation included in the estimated average rate base.

HELCO's REBUTTAL POSITION

Q. Has HELCO made any changes to the rate base estimates presented in direct testimony?

A. Yes. The estimated average rate base for the test year 2006, which takes into account settlement discussions with the Consumer Advocate, is $357,239,000 as shown in HELCO-R-1601.

Q. How does the revised estimated average rate base compare with the estimate provided in direct testimony?

A. The revised average rate base estimate is $11,897,000 less than the estimate provided in direct testimony.

Changes in Rate Base

Q. Why did the average rate base change since direct testimony?

A. The rate base estimates were revised to reflect recorded 2006 balances, to reflect changes in estimates of its components, to reflect the results of the settlement discussions between the Company and the Consumer Advocate, and/or to correct errors.

Q. Who explains the changes in rate base components?

A. The following is a list of the witnesses who discuss rate base components in their areas.

Rate Base Component	Witness
Cost of removal Salvage Depreciation accrual	Ms. Deorna Ikeda HELCO RT-12
Plant additions Retirements Joint pole sales Property held for future use	Mr. Jose Dizon HELCO RT-14
Fuel inventory	Ms. Lisa Giang HELCO RT-4
Production inventory	Mr. Norman Verbanic HELCO RT-5
Transmission & Distribution ("T&D") inventory	Mr. Jay Ignacio HELCO RT-6
Unamortized net Statement of Financial Accounting Standards 109 ("SFAS 109") regulatory asset	Ms. Lorie Ishii HELCO RT-13
Pension asset	Mr. Paul Fujioka HELCO RT-9
OPEB amount	Mr. Paul Fujioka HELCO RT-9
Unamortized contributions in aid of construction ("CIAC") Customer advances	Mr. Jose Dizon, HELCO RT-14
Customer deposits	Mr. Paul Fujioka HELCO RT-7
Accumulated deferred income taxes Unamortized investment tax credits ("ITC")	Ms. Lorie Ishii HELCO RT-13
Working cash	Ms. Gayle Ohashi HELCO RT-16

Net Cost of Plant In Service

Q. What is the revised test year estimate of the average net cost of plant in service?

A. The revised estimated average net cost of plant in service for the test year 2006 is $448,296,000 as shown on HELCO-R-1602.

Q. Why did the estimate of the average net cost of plant in service change?

A. The decrease in the average net cost of plant in service reflects adjustments that were made to certain rate base components as discussed by Mr. Dizon in HELCO RT-14 and Ms. Ikeda in HELCO RT-12.

Property Held For Future Use

Q. What is the revised test year estimate of the average property held for future use?

A. The estimated average property held for future use for the test year 2006 is $129,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average property held for future use change?

A. The increase in the average property held for future use is explained by Mr. Dizon in HELCO RT-14.

Fuel Inventory

Q. What is the revised test year estimate of the average fuel inventory?

A. The revised estimated average fuel inventory for the test year 2006 is $8,241,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average fuel inventory change?

A. The decrease in the average fuel inventory is explained by Ms. Giang in HELCO RT-4.

Materials and Supplies Inventory

Q. What is the revised test year estimate of the average materials and supplies inventories?

A. The revised estimated average materials and supplies inventories for both production and T&D for the test year 2006 is $3,350,000, as shown on HELCO-R-1605. The test year estimate includes an adjustment for the payment lag associated with the investment in inventory.

Q. Why did the estimate of the average materials and supplies inventories change?

A. The increase in the average materials and supplies inventories is due to a correction of an error made in the presentation of the materials and supplies inventory in direct testimony. The error and correction was presented and explained in response to CA-IR-448 (T-16).

Q. Did the Consumer Advocate accept the correction presented by the Company?

A. As explained in response to HELCO/CA-IR-111, the Consumer Advocate accepted the correction to the T&D materials and supply inventory and the corrected balance is $2,325,000 as shown in HELCO-R-1605. However, the Consumer Advocate did not accept the correction to the production materials and supply inventory.

Q. Have the Company and the Consumer Advocate reached an agreement on the production materials and supply inventory?

A. Yes. The Company and the Consumer Advocate have agreed. The agreed upon production materials and supply inventory is $1,025,000 as shown in HELCO-R-1605.

<u>Unamortized Net SFAS 109 Regulatory Asset</u>

Q. What is the revised test year estimate of the average net regulatory asset?

A. The revised estimated average unamortized net SFAS 109 regulatory asset for the test year 2006 is $10,772,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average unamortized net SFAS 109 regulatory asset change?

A. The decrease in the average unamortized net SFAS 109 regulatory asset reflects adjustments that were made as explained by Ms. Ishii in HELCO RT-13.

<u>Pension Asset</u>

Q. What is the revised test year estimate of the average pension asset?

A. The revised estimated average pension asset for the test year 2006 is $14,143,000, as shown on HELCO-R-1601.

Q. Does the pension asset represent the same investment as the prepaid pension asset that was presented in direct testimony?

A. Yes. Mr. Fujioka describes the pension asset and the prepaid pension asset in HELCO-RT-9.

Q. Does the Consumer Advocate's proposed pension tracking mechanism described by Mr. Carver in CA-T-3 impact the pension asset in rate base?

A. No. The Consumer Advocate's proposed pension tracking mechanism does not impact the pension asset included in rate base in this proceeding. Ms. Sekimura discusses the pension tracking mechanism in more detail in HELCO RT-18.

<u>OPEB Amount</u>

Q. What is the revised test year estimate of the average OPEB amount?

A. The estimated average OPEB amount for the test year 2006 is $0, as shown on HELCO-R-1601. This estimate is the same as the estimate presented in direct testimony.

Q. Does the OPEB amount represent the same investment as the unamortized OPEB regulatory asset and the OPEB liability that was presented in direct testimony?

A. Yes. Mr. Fujioka describes the OPEB amount, the OPEB regulatory asset and the OPEB liability in HELCO-RT-9.

Q. Does the Consumer Advocate agree with HELCO's OPEB amount of zero?

A. Yes. The Consumer Advocate's rate base calculations in Exhibit CA-101 include a net impact on rate base of zero from inclusion of the unamortized OPEB regulatory asset and the OPEB liability.

Unamortized CIAC

Q. What is the revised test year estimate of the average unamortized CIAC?

A. The revised estimated average unamortized CIAC for the test year 2006 is $58,431,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average unamortized CIAC change?

A. The average unamortized CIAC increased as a result of updating all CIAC items including cash and in-kind CIAC receipts, transfer from advances, refunds, general excise tax payable, and amortization to reflect recorded as of December 31, 2006. The calculation supporting the revised estimate of unamortized CIAC is shown on HELCO-R-1603. The changes are discussed by Mr. Dizon in HELCO RT-14.

Customer Advances

Q. What is the revised test year estimate of the average customer advances?

A. The revised estimated average customer advances for the test year 2006 is $30,189,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average customer advances change?

A. The average customer advances increased as a result of updating the estimate of receipts, refunds, transfers to contributions, and general excise tax payable to reflect recorded as of December 31, 2006. The calculation supporting the revised estimate of average customer advances is shown on HELCO-R-1604. The changes are discussed by Mr. Dizon in HELCO RT-14.

Customer Deposits

Q. What is the revised test year estimate of the average customer deposits?

A. The estimated average customer deposits for the test year 2006 is $931,000, as shown on HELCO-R-1601. This estimate is the same as the estimate presented in direct testimony.

Accumulated Deferred Income Taxes

Q. What is the revised test year estimate of the average accumulated deferred income taxes?

A. The revised estimated average accumulated deferred income taxes for the test year 2006 is $25,870,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average accumulated deferred income taxes change?

A. The increase in the average accumulated deferred income taxes reflects adjustments that were made as discussed by Ms. Ishii in HELCO RT-13.

Unamortized Investment Tax Credits

Q. What is the revised test year estimate of the average unamortized investment tax credits?

A. The revised estimated average unamortized ITC for the test year 2006 is $11,562,000, as shown on HELCO-R-1601.

Q. Why did the estimate of the average unamortized ITC change?

A. The decrease in the average unamortized ITC reflects adjustments that were made as discussed by Ms. Ishii in HELCO RT-13.

POSITIONS OF THE PARTIES

Q. What rate base issues were the Company and the Consumer Advocate in agreement in this docket?

A. The Consumer Advocate and the Company were in agreement on the methodology used to derive the average balances for the rate base items at present and proposed rates.

Q. Please describe the differences in rate base between the Consumer Advocate and the Company that were subsequently settled on.

A. The rate bases were different because the parties differed on:

1) the estimates of balances for the various components of rate base other than working cash;
2) the revenue tax payment lag days; and
3) the estimates of the expenses included in the working cash calculations.

Q. Who addresses the differences between the Consumer Advocate and HELCO with respect to the estimates of balances for the various rate base components not addressed in this testimony?

A. The various witnesses listed earlier in my testimony describe HELCO's position and address the Consumer Advocate's positions on any differing estimates of the various components of rate base. The various witnesses also discuss the results of the settlement discussions with the Consumer Advocate.

Q. Who addresses the differences between the Consumer Advocate and HELCO with respect to the revenue tax payment lag days?

A. I will discuss these differences below.

Q. Who addresses the differences between the Consumer Advocate and HELCO with respect to the estimates of expenses for the working cash items?

A. The expense estimates are addressed by the HELCO witnesses who present the Company's estimates of operating expenses. These witnesses also discuss the results of the settlement discussions with the Consumer Advocate.

Q. Are there any remaining areas of disagreement between the Consumer Advocate and the Company?

A. No. As a result of the settlement discussions, there are no areas of disagreement between rate base presented in the Company's rebuttal testimony and the Consumer Advocate's settlement position.

WORKING CASH

Q. What will you address in this section of your testimony?

A. This section of my testimony will address changes made to the working cash calculation since the filing of my direct testimony. I will also discuss a minor error related to the inclusion of the pension asset amortization of $2,554,000 in the working cash calculation. Including the pension asset amortization in the working cash calculation has a minimal impact to rate base and the revenue requirement.

Q. Was there any change in HELCO's estimate of working cash?

A. Yes. The revised estimate of working cash is $2,460,000 at present rates and $(710,000) at proposed rates as shown on HELCO-R-1606.

Q. Why did the estimated working cash change?

A. The change to the working cash estimate was due to a change in the fuel payment lag days, a change in the revenue tax payment lag days, and changes in the estimates of annual expense amounts.

Q. Why was there a change to the fuel payment lag days?

A. The fuel payment lag days calculation was revised resulting in a change in the lag days from 13 days to 16 days. This revision was presented in response to CA-IR-

447 (T-16). The fuel payment lag days calculation was revised to be based on actual payments made to each fuel vendor in 2005. The payment lag days were previously calculated based on a test year forecast of deliveries and payments according to the payment terms in the respective contracts with each vendor.

Q. Does the Consumer Advocate agree to the change in the fuel payment lag days?

A. Yes. In response to HELCO/CA-IR-112, the Consumer Advocate agreed to the change in fuel payment lag days, subject to review of the Company's update to the revenue tax payment lag days which is described below. However, the Consumer Advocate and the Company have subsequently reached an agreement on the working cash estimate and calculation at present and proposed rates.

Q. Why did the revenue tax payment lag days change?

A. The revenue tax payment lag days was corrected from 88 days in direct testimony to 84 days in response to CA-IR-448 (T-16). Further corrections were made to the revenue tax payment lag day calculation resulting in a payment lag of 74 days as presented here. Several corrections were made to the calculation of the Public Service Company ("PSC") tax, Franchise Royalty Tax and PUC Fee payment lag days. These revisions are described and illustrated in HELCO's response to CA-IR-448. Subsequent to the filing of this response HELCO identified three additional errors in the determination of the PSC tax payment lag days which required correction of the payment lag day calculation. This correction resulted in a revenue tax payment lag of 74 days as shown on HELCO-RWP-1606, page 1.

Q. Please describe the three errors identified by HELCO subsequent to the filing of the response to CA-IR-448 (T-16).

A. The first error was that the calculation of the total payment lag days incorrectly added the check clearing lag days to the average service period days. This error resulted in an overstatement of the total PSC tax payment lag days. The calculation was corrected and the format of the calculation was also revised to be consistent with the format used for other working cash components and to clearly illustrate the calculation of the payment lag days and check clearing lag days. This is shown on HELCO-RWP-1606, page 2.

Second, the monthly PSC tax payments made were incorrectly assumed to relate to the tax liability for that particular monthly period. Monthly service periods were then used as a basis of determining the payment lag days for each monthly payment. However, as determined by the Commission in Decision and Order No. 11893 (Docket No. 6999), the payment of a public service company's tax liability is paid in the year to which the liability relates. Also, as noted in the PSC Tax Law in the Hawaii Revised Statutes, Chapter 239, in cases where the total tax liability exceeds $100,000 the tax is to be paid in 12 equal installments. Therefore, the use of monthly service periods was incorrect as the monthly payments do not represent a payment for doing business in that month. Rather, the monthly payment represents a monthly installment payment of the total tax liability due for doing business in that particular year. The service periods were revised as shown on HELCO-RWP-1606, page 2.

The third error was the use of the actual PSC tax payment amounts made to the State of Hawaii and County of Maui to determine the weighted average PSC tax payment lag days. The actual PSC tax payment amounts do not accurately reflect the weighting of payments made to the State of Hawaii and to the County of Maui. This results in a distortion of the calculation of the weighted payment lag days. The total tax liability for a particular year is not determined until the filing of the annual tax return in April of that year. As the annual tax liability is not known prior to this, the actual monthly installment payments made in January through April are based on estimates. The monthly installment payments made in May through December are then subsequently adjusted to ensure that the total of the monthly installment payments made during the year equal the tax liability filed in the annual return.

Q. What are the revised estimates of the working cash annual expense amounts?

A. The revised test year estimates of the expense amounts for the working cash items are shown in HELCO-R-1606, page 1, column D, "Annual Amount".

Q. Who estimates these revised working cash item expense amounts?

A. Changes to the test year estimates of the expense amounts for the working cash items are provided by the HELCO witnesses who present the Company's estimates of operating expenses. These witnesses also discuss the results of the settlement discussions with the Consumer Advocate.

Q. Please describe the minor error in the working cash calculation related to the pension asset amortization of $2,554,000 and the insignificant impact to rate base and the revenue requirement.

A. As described by Ms. Tayne Sekimura in HELCO RT-18, the pension asset amortization of $2,554,000 is included in the revenue requirements. In the revenue requirements modeling, this amortization expense impacted the working cash calculation shown on HELCO-R-1606. Modifications to the working cash calculation in the revenue requirement model to account for the pension asset amortization were not made given the short time frame between settlement with the Consumer Advocate and filing of HELCO's rebuttal testimony. Thus, rate base is understated by approximately $31,000 and revenue requirements are understated by approximately $5,000 as a result of changes in working cash.

Q. Are there any remaining areas of disagreement between the Consumer Advocate and the Company in regards to the working cash estimate and calculation?

A. No. As a result of the settlement discussions, there are no areas of disagreement between the working cash estimate and calculation presented in the Company's rebuttal testimony and the Consumer Advocate's settlement position.

SUMMARY

Q. What is your conclusion as to the rate base proposed by the Company?

A. HELCO proposes that the Commission allow the use of an average rate base of $360,409,000 at present rates and $357,239,000 at proposed rates for the calculation of revenue requirements in this docket

Q. Does this conclude your testimony?

A. Yes.

Hawaii Electric Light Company, Inc.
2006 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2005	12/31/2006	Average for 2006	HELCO Reference
Net Cost of Plant in Service	439,895	456,696	448,296	R-1602
Property Held for Future Use	129	129	129	RWP-1402
Fuel Inventory	8,241	8,241	8,241	R-408
Materials & Supplies Inventories	3,322	3,377	3,350	R-1605
Unamortized Net SFAS 109 Regulatory Asset	10,888	10,655	10,772	R-1305
Pension Asset	15,515	12,771	14,143	R-904
OPEB Amount	0	0	0	R-905
Working Cash at Present Rates	2,460	2,460	2,460	R-1606
Total Investments in Assets	480,450	494,329	487,390	
Funds from Non-Investors				
Unamortized CIAC	56,925	59,936	58,431	R-1603
Customer Advances	28,597	31,780	30,189	R-1604
Customer Deposits	920	941	931	706
Accumulated Deferred Income Taxes	26,108	25,631	25,870	R-1304
Unamortized ITC	11,247	11,877	11,562	R-1303
Total Deductions	123,797	130,165	126,981	
Average Rate Base at Present Rates			360,409	
Change in Working Cash			(3,170)	R-1606
Average Rate Base at Proposed Rates			357,239	

NOTE: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum. Depreciation, Removal Reg. Liability, Acc. Retirement Oblig.	Net Plant In Service	HELCO Reference
RECORDED BALANCES - 12/31/05	769,539	(317,408)	452,131	
Adjustments	64		64	WP-1204
Settlement Adjustments	(12,898)	598	(12,300)	
ADJUSTED BALANCES - 12/31/05	756,705	(316,810)	439,895	RWP-1401
ACTUAL CHANGES in 2006:				
Net Plant Additions	47,729		47,729	RWP-1401
Joint Pole Sales	(798)		(798)	RWP-1401
ICS Transfer	442		442	RWP-1401
Cost of Removal		1,883	1,883	R-1202
Salvage		19	19	R-1202
Depreciation Accrual		(32,258)	(32,258)	R-1202
Depreciation Adjustment related to ICS transfer		(216)	(216)	R-1202
Retirements [1]	(4,654)	4,654	0	RWP-1401
RECORDED BALANCES - 12/31/06	799,424	(342,728)	456,696	
AVERAGE 2006 BALANCE			448,296	

[1] Original cost of actual retirements for the respective year.

Hawaii Electric Light Company, Inc.
Unamortized Contributions In Aid of Construction
($ in thousands)

		HELCO Reference
RECORDED BALANCES - 12/31/05	56,555	
Adjustments	370	1201
ADJUSTED BALANCE - 12/31/05	56,925	
RECORDED in 2006:		
Cash Receipts	2,864	RWP-1403
In-Kind Receipts	1,471	CA-SIR-51
Transfer from Advances	1,983	RWP-1404
Refunds	(152)	RWP-1405
General Excise Tax Payable [1]	(108)	RWP-1403
Amortization	(3,047)	1201
RECORDED BALANCE - 12/31/06	59,936	
AVERAGE 2006 BALANCE	58,431	

NOTE: Totals may not add exactly due to rounding.

[1] General Excise Tax amounts included in cash receipts are paid to the State of Hawaii.

Hawaii Electric Light Company, Inc.
Customer Advances
($ in thousands)

		HELCO Reference
RECORDED BALANCES - 12/31/05	28,597	
RECORDED in 2006:		
Receipts	7,613	RWP-1406
Refunds	(2,295)	RWP-1407
Transfers to Contributions	(1,983)	RWP-1404
General Excise Tax Payable [1]	(152)	RWP-1406
RECORDED BALANCE - 12/31/06	31,780	
AVERAGE 2006 BALANCE	30,189	

NOTE: Totals may not add exactly due to rounding.

[1] General Excise Tax amounts included in cash receipts are paid to the State of Hawaii.

Hawaii Electric Light Company, Inc.

Materials & Supplies Inventory

($ in thousands)

	12/31/2005	12/31/2006	Average for 2006	HELCO Reference
Production Inventory	1,007	1,062	1,035	R-502
Adjustment to Inventory related to Accounts Payable	(10)	(10)	(10)	WP-1603 p. 1
Adjusted Production Inventory	997	1,052	1,025	(a)
Transmission & Distribution Inventory	2,512	2,512	2,512	R-606
Adjustment to Inventory related to Accounts Payable	(187)	(187)	(187)	WP-1603 p. 1
Adjusted T&D Inventory	2,325	2,325	2,325	(b)
Total Materials & Supplies	3,322	3,377	3,350	(a) + (b)

Hawaii Electric Light Company, Inc.

WORKING CASH ITEMS, 2006

($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per HELCO-WP-708				HELCO-RWP-2101					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	38	CA-IR-448	16	22		78,091	214	4,707	214	4,707
O&M Labor	38	HELCO WP-1606 p. 5	12	26		19,199	53	1,368	53	1,368
Purchased Power	38	HELCO WP-1606 p. 24	37	1		117,210	321	321	321	321
ITEMS PROVIDING WORKING CASH:										
O&M Nonlabor	38	HELCO WP-1606 p. 20	39	(1)		32,390	89	(89)	89	(89)
Revenue Taxes - Present Rates	38	HELCO RWP-1605 p. 1	74	(36)		28,736	79	(2,834)		
Revenue Taxes - Proposed Rates	38	HELCO RWP-1605 p. 1	74	(36)		30,912			85	(3,049)
Income Taxes - Present Rates	38	HELCO WP-1606 p. 32	162	(124)		2,980	8	(1,012)		
Income Taxes - Proposed Rates	38	HELCO WP-1606 p. 32	162	(124)		11,680			32	(3,968)
Total WORKING CASH								2,460		(710)
Change in WORKING CASH										(3,170)

REBUTTAL TESTIMONY OF
ROGER A. MORIN, PH.D.

ON BEHALF OF

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Rate of Return on Common Equity

INTRODUCTION

Q. Please state your name, business address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted direct testimony as HELCO T-17.

Q. Please describe the purpose of your rebuttal testimony.

A. I will rebut Mr. David Parcell's cost of capital testimony, CA-T-4, submitted on behalf of the Division of Consumer Advocacy ("Consumer Advocate").

Q. Please summarize Mr. Parcell's rate of return recommendation.

A. Mr. Parcell recommends that a return allowance of 9.5% - 10.25% be employed on the common equity capital of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company"). In determining HELCO's cost of equity, Mr. Parcell applies a discounted cash flow ("DCF") analysis to two groups of electric utilities. For the growth component of his DCF analysis, he uses a blend of analysts' growth forecasts, historical growth rates, and the earnings retention method. Mr. Parcell concludes from his DCF estimates summarized on page 37 of his testimony that the DCF estimate of HELCO's cost of equity lies in the upper portion of a range of 8.0% - 9.5%.

Mr. Parcell also applies a capital asset pricing model ("CAPM") analysis to the same groups of companies, using long-term Treasury bond yields as proxies for the risk-free rate and Value Line beta estimates. I point out that Mr. Parcell has departed drastically from prior testimonies as to how he estimates the market risk premium ("MRP") component of the CAPM that causes him to report lower CAPM results. Lastly, Mr. Parcell performs a Comparable Earnings analysis on a sample of utilities and a sample of unregulated industrial companies. From his three analyses, Mr. Parcell concludes that HELCO's cost of common equity capital lies in the range of 9.5% - 10.25%

Q. Does Mr. Parcell agree with HELCO's proposed test year capital structure?

A. Yes. On page 27 of his testimony, Mr. Parcell adopts the Company's proposed test year 2006 capital structure for ratemaking purposes as described in HELCO T-18.

Q. Please summarize your specific criticisms of Mr. Parcell's testimony.

A. I have eight specific comments:

1. Allowed return out of the mainstream. Mr. Parcell's recommended return is outside the zone of currently allowed rates of return for his two samples of companies.

2. The DCF Model Understates the Cost of Equity. It is well-known that application of the DCF model to utility stocks understates the investor's expected return when the market-to-book ("M/B") ratio exceeds unity. This is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity.

3. Understated Dividend Yield. Mr. Parcell's dividend yield component is understated because it is not consistent with the annual form of the DCF model.

It is inappropriate to increase the dividend yield by adding one-half of the future growth rate (1 + ½ g) to the spot dividend yield. The appropriate manner of computing the expected dividend yield when using the plain vanilla annual DCF model is to add the full growth rate rather than one-half of the growth rate. This error understates the DCF results by some 20 basis points. Mr. Parcell's dividend yield component is also understated by another 20 basis points because it ignores the time value of quarterly dividend payments.

4. DCF Dividend Yield and Flotation Costs. Mr. Parcell's dividend yield component is understated by 30 basis points because it does not sufficiently allow for flotation costs, and, as a result, a legitimate expense is left unrecovered.

5. DCF Growth Rates. The retention growth method contains a logical inconsistency because one is forced to assume the answer to implement the method. Moreover, whenever the dividend payout ratio is expected to change, the implementation of the standard DCF model is of questionable relevance.

6. DCF Reliability. The huge variability in the DCF results demonstrates the lack of reliability of the DCF approach and the importance of selecting relatively large sample sizes as opposed to small sample sizes consisting of a handful of companies when using the DCF model.

7. CAPM Risk-Free Rate. The correct proxy for the risk-free rate in the CAPM is the return on very long-term Treasury bonds.

8. CAPM Market Risk Premium. Mr. Parcell has departed drastically from prior testimonies as to how he estimates the MRP component of the CAPM and has understated the MRP substantially compared to his past estimates. Moreover, Mr. Parcell's three MRP proxies are beleaguered by conceptual errors.

I also find that Mr. Parcell's criticisms of my testimony are largely unfounded.

1. ALLOWED RETURNS

Q. Is Mr. Parcell's rate of return on common equity ("ROE") recommendation compatible with currently allowed returns in the electric utility industry?

A. No, it is not. ROE awards in the industry exceed Mr. Parcell's recommended ROE of 9.50% - 10.25% for HELCO. The currently allowed ROEs for the electric utilities in both of Mr. Parcell's comparable groups as reported in AUS Utility Reports survey for February 2007 exceed his recommended ROE.

2. DCF MODEL UNDERSTATEMENT

Q. Does the DCF model understate the cost of equity?

A. Yes, it does. As I discussed earlier, application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar. The DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently. Mr. Parcell's comment on page 37 of his testimony is well-taken: "*current financial conditions (low interest rates and high market-to-book ratios for utilities) have the effect of driving DCF results to low levels by historic standards.*"

3. DIVIDEND YIELD

Q. Please discuss Mr. Parcell's dividend yield component in the DCF model.

A. I believe that the dividend yield component used in Mr. Parcell's DCF analysis is downward-biased. Mr. Parcell uses a spot dividend yield inflated by one-half of the expected dividend growth $D_o(1 + 1/2\ g)$ rather than the correct expected dividend yield which is inflated by one full year of growth, $D_o(1 + g)$. This procedure fails to measure the full dividend flows expected by the investor, contrary to the spirit and fundamental nature of the DCF model.

The annual DCF model states very clearly that the expected rate of return on a stock is equal to the expected dividend at the end of the year divided by the current price of the stock, plus the expected growth rate.

Since the appropriate dividend to use in a DCF model is the prospective dividend to be received at the end of the year rather than one half of that dividend, Mr. Parcell's approach understates the proper dividend yield. This creates a downward bias in his dividend yield component, and underestimates the cost of equity by approximately 20 basis points. For example, for a spot dividend yield of 5% and a growth rate of 5%, Mr. Parcell's estimated dividend yield is 5% * (1 + .05/2) = 5.1%. The correct dividend yield to employ is 5% * (1 + .05) = 5.3%, which is about 20 basis points higher.

4. FLOTATION COSTS

Q. Please discuss Mr. Parcell's testimony with regard to flotation costs.

A. Mr. Parcell does not include any allowance whatsoever for flotation costs, and his DCF methodology therefore understates the expected return on equity by approximately 30 basis points. As a result, a legitimate stockholder expense is left unrecovered.

5. DCF GROWTH RATES

Q. Please describe Mr. Parcell's methodology for specifying the growth component of the DCF model.

A. As summarized on page 35 of his testimony, Mr. Parcell employs five proxies as a proxy for the expected growth component of the DCF model: 1) historical earnings retention ratio, 2) projected earnings retention ratio,) five-year historical growth rates in dividends, earnings, and book value, 4) projected growth rates in dividends, earnings, and book value, and 5) analysts' forecasts.

Q. Can you comment on Mr. Parcell's earnings retention growth estimate in the DCF model?

A. The earnings retention technique of specifying growth is beleaguered with serious conceptual and empirical difficulties, and results from its use should be dismissed. The retention growth method contains a logical flaw when applied to a regulated utility: the method requires an estimate of ROE to be implemented, which is the very quantity Mr. Parcell is attempting to estimate. The method is thus circular. Moreover, the empirical finance literature demonstrates that the retention growth method of determining growth is a poor explanatory variable of market value, and is not as significantly correlated to measures of value, such as stock price and price/earnings ratios.

In conclusion, Mr. Parcell's retention growth rates should be viewed with caution.

Q. Are the historical growth rates of electric utilities reliable?

A. No, they are not. Mr. Parcell uses historical growth rates in dividends, earnings, and book value as proxies for expected growth, as shown on CA-407 page 3. If historical growth rates are to be representative of long-term future growth rates, they must not be biased by non-recurring events. This was certainly the case for electric utilities, where growing competition, diversification programs, acquisitions, restructurings and write-off activities have exerted a dilutive effect on historical earnings and dividends. In such cases, it is obvious that analysts' growth forecasts provide a more realistic and representative growth proxy for what is likely to happen in the future than historical growth. In any event, historical growth rates are somewhat redundant given that analysts formulate their growth expectations based in part on historical patterns.

In conclusion, Mr. Parcell's historical growth rates should be given considerably less weight than the analysts' growth forecasts.

Q. What does the published academic literature say on the subject of growth rates in the DCF model?

A. Published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts. Cragg and Malkiel ("Expectations and the Structure of Share Prices," Chicago: University of Chicago Press, 1982) present detailed empirical evidence that the average analysts' expectation is more similar to expectations being reflected in the marketplace than are historical growth rates, and represents the best possible source of DCF growth rates. Cragg and Malkiel show that historical growth rates do not contain any information that is not already impounded in analysts' growth forecasts. A study by Professors Vander Weide and Carleton, "Investor Growth Expectations: Analysts vs. History" (*The Journal of Portfolio Management*, Spring 1988), also confirms the superiority of analysts' forecasts over historical growth extrapolations. Another study by Timme & Eiseman, "On the Use of Consensus Forecasts of Growth in the Constant Growth Model: The Case of Electric Utilities," *Financial Management,* Winter 1989, produces similar results.

Q. Do you see any dangers in relying on Value Line as an exclusive source of forecasts in applying the DCF model?

A. Yes, I do. Mr. Parcell places equal weight on the Value Line forecast and the market consensus forecast. As one surrogate for growth in the DCF model, Mr.

Parcell used an average of the three Value Line growth forecasts for earnings, dividend, and book value. Mr. Parcell's heavy reliance on Value Line growth forecasts runs the risk that such forecasts are not representative of investors' consensus forecast. One would expect that averages of analysts' growth forecasts such as those contained in First Call and/or Zacks, rather than one particular firm's forecast, are more reliable estimates of the investors' consensus expectations likely to be impounded in stock prices.

Q. Are investors expecting growth rates equal to Mr. Parcell's range?

A. No. The best evidence shows that investors are expecting growth rates higher than Mr. Parcell has found. For his first group of electric utilities, Mr. Parcell has found (see his exhibit CA-407 page 4 of 4) growth rates ranging from 1.8% to 5.6%, with a mean of 3.9%, from all the proxies he used. As indicated earlier, the retention growth estimate should be discarded from the analysis, historical growth rates should be given considerably less weight, and Value Line forecasts are somewhat unrepresentative, which leaves us with the consensus analyst forecast of 5.6%. This is 170 basis points (1.7%) above Mr. Parcell's mean estimate of 3.9%, and therefore Mr. Parcell's DCF cost of equity estimates are downward-biased by about 200 basis points from this understatement alone once we factor in the appropriate expected dividend yield component. The same is true for Mr. Parcell's second group of companies.

6. DCF RELIABILITY

Q. Is there any evidence that Mr. Parcell's DCF results are unreliable?

A. Yes, there is. The two tables below reproduce Mr. Parcell's DCF estimates (dividend yield plus growth) for both of his samples of electric utilities using each of the five proxies for growth.

Mr. Parcell's First Group of Electric Utilities
DCF Results

Company	Historic Retention Growth	Projected Retention Growth	Historic Per Share Growth	Projected Per Share Growth	Analysts Forecast Growth
CH Energy	5.9%	6.3%	4.3%	5.9%	
Great Plains Energy	8.3%	6.7%	7.6%	6.5%	7.3%
NSTAR	7.7%	8.0%	6.4%	9.8%	9.8%
Otter Tail	8.5%	6.9%	5.8%	9.8%	12.8%
Pinnacle West	6.6%	7.9%		9.3%	7.1%
PNM Resources	8.9%	8.9%		7.9%	10.1%

Source: Mr. Parcell exhibit CA-407 page 4

Mr. Parcell's Second Group of Electric Utilities
DCF Results

Company	Historic Retention Growth	Projected Retention Growth	Historic Per Share Growth	Projected Per Share Growth	Analysts Forecast Growth
Cleco Corp	8.3%	6.9%	5.8%	10.4%	14.2%
Empire District Electric	5.5%	6.8%		9.4%	8.6%
Hawaiian Electric Industries	7.6%	6.9%	5.8%	6.3%	7.6%
IDACORP	5.2%	7.2%		6.5%	8.2%
Puget Energy	5.9%	7.0%		7.7%	8.2%

Source: Mr. Parcell exhibit CA-407 page 4

In the first table, the DCF results are scattered all over, ranging from a low of 4.3% for CH Energy to a high of 12.8% for Otter Tail. The situation is even worse in the second table with the DCF results ranging from a low of 5.2% for IDACORP to a high of 14.2% for Cleco. Several estimates (boxed cells) are barely above, and even below, the cost of debt for these companies. The huge variability in the results demonstrates the lack of reliability of the DCF approach, especially when employing very small groups of comparable companies.

This is precisely why it is important to select relatively large sample sizes as opposed to small sample sizes consisting of a handful of companies when using the DCF model. Samples consisting of only five or six companies, such as the two samples selected by Mr. Parcell, are simply too small. This is because the electric utility industry capital market data is highly unstable and fluid at this time. Confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Utilizing a large portfolio of companies reduces the chance of either overestimating or underestimating the cost of equity for an individual company.

A far superior approach to defining small narrowly-defined company samples is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the Company and the industry average. In the current unstable industry environment, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities. We can see this instability by comparing Mr. Parcell's first group of electric utilities to his second group defined as per the Commission's past screening criteria. The groups are totally different, with not even one company in common.

Q. Please comment on Mr. Parcell's criticism of your DCF analysis.

A. On page 58 of his testimony, Mr. Parcell takes issue with my use of only one indicator of growth in the DCF analysis, namely, analyst growth projections and that I have ignored historical and projected growth rates in dividends and book value. In my direct testimony, I discussed the impropriety of relying on "near-term" dividend growth because it is widely expected that energy utilities will continue to lower their dividend payout ratio over the next several years in response to increased business risk, and that earnings and dividends are not expected to grow at the same rate in the future. In my direct testimony and earlier in my rebuttal, I also discussed the merits of using consensus analysts' earnings growth forecasts in the DCF model and the supportive empirical literature.

Q. Please discuss the use of analysts' forecasts in applying the DCF model to utilities.

A. As discussed earlier, the best proxy for the growth component of the DCF model is analysts' long-term earnings growth forecasts. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Published studies in the academic literature demonstrate that growth forecasts made by security analysts are reasonable indicators of investor expectations, and that investors rely on analysts' forecasts.

7. CAPM RISK-FREE RATE

Q. Do you agree with Mr. Parcell's comments on your choice of the risk-free rate in the CAPM analysis?

A. No, not quite. Mr. Parcell uses a risk-free rate based on the prevailing yield on 20-year Treasury bonds rather than the yield based on 30-year Treasury bonds. The appropriate proxy for the risk-free rate in the CAPM is the return on very long-term Treasury bonds. This is simply because common stocks are very long-term instruments more akin to very long-term bonds. The ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Because common equity has an infinite life-span, the inflation expectations embodied in its market-required rate of return will be equal to the inflation rate anticipated to prevail over the long-term. Among U.S. Treasury securities, 30-year U.S. Treasury bonds have the longest term to maturity. Therefore, 30-year U.S. Treasury bonds will most closely incorporate within their yield the inflation expectations that influence the prices of common stocks.

On page 51 of his testimony, Mr. Parcell objects to the use of 30-year bonds because the U.S. Treasury has not issued such bonds on a continuous basis in recent years. That is immaterial. In the same way that we can use stock prices in the application of the DCF model to a given company even though that company has not issued stock in the recent past, we can rely on bond prices of 30-year Treasury bonds and the implied yields. 30-year Treasury bonds are actively traded on secondary markets and provide useful price/yield signals.

On page 51, Mr. Parcell also objects to the use of 30-year bonds because the Ibbotson series I used to develop my MRP is based on 20-year bond returns and not on 30-year returns. Because 30-year bonds were not always traded or even available throughout the entire 1926-2006 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

Although I disagree with the use of 20-year Treasury bonds as proxies for the risk-free rate, I do not have any serious disagreement with Mr. Parcell's actual estimate of 4.83% for the risk-free rate in the CAPM analysis. As a practical matter, there is little difference in yield between 20- and 30-year Treasury bonds at this time.

8. CAPM MARKET RISK PREMIUM

Q. Do you agree with Mr. Parcell's beta estimates in his CAPM analysis?

A. Yes, I do.

Q. How does Mr. Parcell estimate the market risk premium component of the CAPM?

A. In order to determine the MRP component of his first CAPM analysis, Mr. Parcell relies on three estimates. First, he examines the accounting returns on book equity (ROE) on the S&P 500 Index companies group over the 1978-2005 period and derives a MRP of 6.19%, that is, an average accounting ROE of 14.09% less the average risk-free rate of 7.9% over that same period. Second, he relies on the long-term 6.5% historical MRP reported in the Ibbotson Associates Valuation 2006 Yearbook for the entire 1926-2005 period based on arithmetic averages. Third, he relies on the long-term 4.9% historical MRP also reported in the Ibbotson Associates Valuation 2006 Yearbook for the entire 1926-2005 period but this time based on geometric averages. From these three estimates, Mr. Parcell concludes that the MRP is 5.9%, that is, the average of the three risk premiums. I seriously disagree with all three estimates for several reasons.

Q. What is your major concern with Mr. Parcell's MRP estimate?

A. Not only are there several conceptual deficiencies in Mr. Parcell's MRP estimates, but my major concern is the inconsistent method of calculation from testimony to testimony. Mr. Parcell has departed significantly from past practices in prior testimonies.

Q. What MRP estimate did Mr. Parcell recommend in a recent proceeding regarding Sierra PacifiCorp before the Nevada Commission?

A. In a recent electric utility proceeding regarding Sierra Pacific Power Company before the Nevada Commission (Docket No. 05-10003), Mr. Parcell used a MRP of 7.9% compared to 6.19% in this proceeding as his first of two MRP estimates.

Q. What MRP estimate did Mr. Parcell recommend in a recent proceeding regarding Virginia Natural Gas before the Virginia Commission?

A. In a recent natural gas utility proceeding regarding Virginia Natural Gas before the Virginia Commission (Case No. PUE-2005-00057), Mr. Parcell used a MRP of 8.2% compared to 6.19% in this proceeding as his first of two MRP estimates.

Q. What MRP estimate did Mr. Parcell recommend in a recent proceeding regarding Delmarva Power & Light before the Delaware Commission?

A. In a recent electric utility proceeding regarding Delmarva Power & Light before the Delaware Commission before the Delaware Commission (Docket No. 05-304), Mr. Parcell used a MRP of 8.1% compared to 6.19% in this proceeding as his first of two MRP estimates.

The trend is rather clear. In contrast to the 6.19% estimate used here as his first of two MRP estimates, Mr. Parcell has used MRP estimates ranging from 7.9% to 8.1%, so around 8%. This stands in sharp contrast to the 6.19% used in this proceeding.

Q. Does Mr. Parcell offer any explanation for his deviation from his general practice of estimating the MRP?

A. No, he does not. No explanation is offered for this rather radical departure from past practices.

Q. What would Mr. Parcell's CAPM estimates be had he followed his past practice and relied upon the same MRP estimates as in the past?

A. Substituting a MRP of 8.0% instead of the 5.9% used in this proceeding in Mr. Parcell's CAPM Exhibit CA-409 page 1 produces average CAPM estimates of 12.2% rather than 10.2%.

Q. Do you agree with Mr. Parcell's first estimate of 6.2% for the MRP in his CAPM analysis?

A. Leaving aside the issue of inconsistency, I do not agree with this first estimate. Mr. Parcell has combined *accounting book returns* on equity for the S&P 500 companies with *market returns* on long-term U.S. Treasury bonds in order to arrive at his first estimate of the MRP. In a classic apples and oranges blunder, Mr. Parcell has mismatched accounting (book) returns with market (economic) returns.

Q. Do you agree with Mr. Parcell's second estimate of 6.5% for the MRP in his CAPM analysis?

A. No, not quite. For his second MRP proxy, Mr. Parcell uses a historical risk premium of 6.5%. This estimate was estimated by Ibbotson and Associates in the Stock, Bonds, Bills and Inflation, 2006 Year Book. Over the period 1926 through 2005, Ibbotson's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.3%, and the total return on long-term Treasury bonds was 5.8%. The indicated equity risk premium is 6.5% (12.3% - 5.8% = 6.5%).[1]

As I discussed in my direct testimony, the more accurate way to estimate the market risk premium from historic data is to use the *income* return, not *total* returns, on government bonds. The long-term (1926-2005) market risk premium (based on income returns, as required) is 7.1%, rather than 6.5%.

Ibbotson Associates recommends use of the *income* return on government bonds as a more reliable estimate of the historical market risk premium because the income component of total bond return (*i.e.* the coupon rate) is a better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain).[2] In other words, bond investors focus on income rather than realized capital gains/losses. This correction alone increases Mr. Parcell's CAPM estimate by approximately 55 basis points (the difference between 7.1% and 6.5% times Mr. Parcell's beta of 0.92 shown on Exhibit CA-409 page 1).

Q. Do you agree with Mr. Parcell's third estimate of 4.9% for the MRP in his CAPM analysis?

A. No, I do not. For his third MRP proxy, Mr. Parcell uses a historical risk premium of 4.9% based on the aforementioned Ibbotson & Associates historical MRP study, only this time relying on the geometric average of historical returns instead of the arithmetic average of historical returns.

Q. Is it appropriate to use geometric averages in measuring expected return?

A. No it is not. Arithmetic means are appropriate for forecasting and estimating the

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[1] Parcell Direct Testimony at page 40, line 18.

[2] *See* Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation 2005 Yearbook: Valuation Edition*, 66 (2005).

cost of capital, and geometric means are not.[3] Indeed, the Ibbotson Associates publication from which Mr. Parcell's market risk premium estimate is derived contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital. There is no theoretical or empirical justification for the use of geometric mean rates of returns. Please see Exhibit HELCO-R-1701 for a discussion regarding the theoretical underpinnings, empirical validation, and the consensus of academics on why geometric means are inappropriate for forecasting and estimating the cost of capital.

Q. What is the effect of Mr. Parcell's use of the geometric mean market risk premium?

A. Mr. Parcell's use of the geometric mean market risk premium of 4.9% rather than the arithmetic mean of 6.5% significantly understates the market risk premium, which suggests an understatement of HELCO's cost of equity by approximately 150 basis points using Mr. Parcell's beta for HELCO of 0.92:

$$B_{HELCO} \times (\text{Arithmetic Mean} - \text{Geometric Mean})$$

$$0.92 \times (6.5\% - 4.9\%)$$

$$0.92 \times (1.6\%)$$

$$1.47\%$$

Q. Should the historical market risk premium be estimated using the income component of bond returns or the total return component?

A. In response to Mr. Parcell's criticism on page 52 of his testimony that I have improperly used income returns rather than total returns on bonds, the historical MRP should be computed using the income component of bond returns because

[3] *See* Roger A. Morin, *The New Regulatory Finance*, chapter 4 (2006) and Brealey, et al., *Principles of Corporate Finance* (8th ed. 2006).

the intent, even using historical data, is to identify an expected MRP. As discussed earlier, the use of the income component is a more reliable estimate of the historical MRP because the income component of total bond return (i.e., the coupon rate) is a far better estimate of expected return than the total return (i.e., the coupon rate plus capital gains), because realized capital gains/losses are largely unanticipated by investors.

Q. Please respond to Mr. Parcell's criticism of your second estimate of the market risk premium.

A. On page 53, Mr. Parcell disagrees with my estimate of 13.5% for the return on the aggregate market. This is a surprising criticism given that this estimate is lower than his estimate of 14.09% shown on Exhibit CA-408.

Q. Mr. Parcell claims on page 54 of his testimony that the empirical CAPM inflates the CAPM result for the selected company or industry. Is he correct?

A. No, he is not. For companies with betas less than one, the CAPM understates the return while for companies with betas greater than one, the CAPM overstates the return. I discussed the conceptual and empirical foundations in HELCO-1712, an exhibit to my direct testimony. I should also point out that in the case of utility stocks, the CAPM understates the rate of return on equity by approximately 50 basis points.

Q. Mr. Parcell disagrees with the risk premium methodology because economic conditions today are different and that risk premiums are unstable from year to year. How do you respond?

A. On pages 55-56 of his testimony, Mr. Parcell critiques the risk premium method on two grounds: 1) the method assumes that past is prologue, and 2) the method assumes that the risk premium is constant over time whereas in fact the risk premium results are dominated by the influence of capital gains in many years.

The first criticism is unwarranted. I employed returns realized over long time periods rather than returns realized over more recent time periods. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. A risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

I have ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I have relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate market risk premium minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

Mr. Parcell's second concern is unwarranted as well. The influence of unexpected capital gains is offset by the influence of unexpected capital losses. To the extent that the historical equity risk premium estimated follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. The best estimate of the future risk premium is the historical mean. As I explained in my direct testimony, since I found no evidence that the market price of risk or the amount of risk in common stocks has changed over time, that is, no significant serial correlation in the successive market risk premiums from year to year, it is reasonable to assume that these quantities will remain stable in the future.

Q. What do you conclude from Mr. Parcell's rate of return recommendation?

A. I believe that Mr. Parcell's recommended ROE is understated. Recognition of flotation cost (30 basis points), the proper functional form of the DCF model (20 basis points), a greater emphasis on analysts' growth forecasts in the DCF analysis (200 basis points), and the appropriate historical market risk premium in the CAPM analysis, would suggest returns that are quite consistent with my own ROE recommendation of 11.25% for HELCO if not higher. I consider my critique conservative, for it does not reflect the consistent tendency of the DCF to understate the cost of equity, nor does it reflect the understatement of the cost of equity which results from the plain vanilla form of CAPM analysis used by Mr. Parcell.

Q. Does Mr. Parcell's ROE recommendation take into account interest rate forecasts?

A. No, I do not believe it does. To the extent that interest rates rise from their current levels, the cost of equity determined from recent data will understate future capital costs. The prospect of higher interest rates rather than lower interest rates looms much larger at this time. Indeed, forecasts of long-term interest rates indicate that interest rates are expected to increase slightly from their current levels and, consequently, that the ROE recommended by Mr. Parcell should be reflective of the forecast increase in capital costs.

Q. Does this complete your rebuttal testimony?

A. Yes, it does.

Appendix A

Arithmetic versus Geometric Means in Estimating the Cost of Capital

The use of the arithmetic mean appears counter-intuitive at first glance, because we commonly use the geometric mean return to measure the average annual achieved return over some time period. For example, the long-term performance of a portfolio is frequently assessed using the geometric mean return.

But performance appraisal is one thing, and cost of capital estimation is another matter entirely. In estimating the cost of capital, the goal is to obtain the rate of return that investors expect, that is, a target rate of return. On average, investors expect to achieve their target return. This target expected return is in effect an arithmetic average. The achieved or retrospective return is the geometric average. In statistical parlance, the arithmetic average is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean.

The geometric mean answers the question of what constant return you would have had to achieve in each year to have your investment growth match the return achieved by the stock market. The arithmetic mean answers the question of what growth rate is the best estimate of the future amount of money that will be produced by continually reinvesting in the stock market. It is the rate of return which, compounded over multiple periods, gives the mean of the probability distribution of ending wealth.

While the geometric mean is the best estimate of performance over a long period of time, this does not contradict the statement that the arithmetic mean compounded over the number of years that an investment is held provides the best estimate of the ending wealth value of the investment. The reason is that an investment with uncertain returns will have a higher ending wealth value than an investment which simply earns (with certainty) its compound or geometric rate of return every year. In other words, more money, or terminal wealth, is gained by the occurrence of higher than expected returns than is lost by lower than expected returns.

In capital markets, where returns are a probability distribution, the answer that takes account of uncertainty, the arithmetic mean, is the correct one for estimating discount rates and the cost of capital.

While the geometric mean is appropriate when measuring performance over a long time period, it is incorrect when estimating a risk premium to compute the cost of capital.

Theory

The geometric mean measure the magnitude of the returns, as the investor starts with one portfolio and ends with another. It does not measure the variability of the journey, as does the arithmetic mean. The geometric mean is backward looking. There is no difference in the geometric mean of two stocks or portfolios, one of which is highly volatile and the other of which is absolutely stable. The arithmetic mean, on the other hand, is forward looking in that it does impound the volatility of the stocks.

To illustrate, Table 1 shows the historical returns of two stocks, the first one is highly volatile with a standard deviation of returns of 65% while the second one has a zero standard deviation. It makes no sense intuitively that the geometric mean is the correct measure of return, one that implies that both stocks are equally risky since they have the same geometric mean. No rational investor would consider the first stock equally as risky as the second stock. Every financial model to calculate the cost of capital recognizes that investors are risk averse and avoid risk unless they are adequately compensate for undertaking it. It is more consistent to use the mean that fully impounds risk (arithmetic mean) than the one from which risk has been removed (geometric mean). In short, the arithmetic mean recognizes the uncertainty in the stock market while the geometric mean removes the uncertainty by smoothing over annual differences.

Empirical Evidence

If both the geometric and arithmetic mean returns over the 1926-2004 data are regressed against the standard deviation of returns for the firms in the deciles, the arithmetic mean outperforms the geometric mean in this statistical regression. Moreover the constant of arithmetic mean regression matches the average Treasury bond rate and therefore makes economic sense while the constant for the geometric mean matches nothing in particular. This is simply because the geometric mean is stripped of volatility information and, as a result, does a poor job of forecasting returns based on volatility.

Table 1 Geometric vs. Arithmetic Returns

	Stock A	Stock B
1996	50.0%	11.61%
1997	-54.7%	11.61%
1998	98.5%	11.61%
1999	42.2%	11.61%
2000	-32.3%	11.61%
2001	-39.2%	11.61%
2002	153.2%	11.61%
2003	-10.0%	11.61%
2004	38.9%	11.61%
2005	20.0%	11.61%
Standard Deviation	64.9%	0.0%
Arithmetic Mean	26.7%	11.6%
Geometric Mean	11.6%	11.6%

The following illustration is frequently invoked in defense of the geometric mean. Suppose that a stock's performance over a two-year period is representative of the probability distribution, doubling in one year (r_1 = 100%) and halving in the next (r_2 = -

50%). The stock's price ends up exactly where it started, and the geometric average annual return over the two-year period, r_g, is zero:

$$\begin{aligned} 1 + r_g &= [(1 + r_1)(1 + r_2)]^{1/2} \\ &= [(1 + 1)(1 - .50)]^{1/2} = 1 \\ r_g &= 0 \end{aligned}$$

confirming that a zero year-by-year return would have replicated the total return earned on the stock. The expected annual future rate of return on the stock is not zero, however. It is the arithmetic average of 100% and -50%, (100-50)/2 = 25%. There are two equally likely outcomes per dollar invested: either a gain of $1 when r = 100% or a loss of $0.50 when r = -50%. The expected profit is ($1-$.50)/2 = $.25 for a 25% expected rate of return. The profit in the good year more than offsets the loss in the bad year, despite the fact that the geometric return is zero. The arithmetic average return thus provides the best guide to expected future returns.

What Academics Have to Say

Bodie, Kane, and Marcus cite:

> *"Which is the superior measure of investment performance, the arithmetic average or the geometric average? The geometric average has considerable appeal because it represents the constant rate of return we would have needed to earn in each year to match actual performance over some past investment period. It is an excellent measure of past performance. However, if our focus is on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected future return (assuming, of course, that the expected return does not change over time). In contrast, because the geometric return over a sample period is always less than the arithmetic mean, it constitutes a downward-biased estimator of the stock's expected return in any future year."*
>
> *"Again, the arithmetic average is the better guide to future performance."*

Another way of stating the Bodie, Kane, Marcus argument in favor of the arithmetic mean is that the latter is the best estimate of the future value of the return distribution because it represents the expected value of the distribution. It is most useful for determining the central tendency of a distribution at a particular time, that is, for cross-sectional analysis. The geometric mean, on the other hand, is best suited for measuring an investment's compound rate of return over time, that is, for time-series analysis. This is the same argument made by Ibbotson Associates (2005) where it is shown, using probability theory, that future terminal wealth is given by compounding the arithmetic mean, and not the geometric mean. In other words, if we accept the past as prologue, the best estimate of a future year's return based on a random distribution of the prior years' returns is the arithmetic average. Statistically, it is our best guess for the holding-period return in a given year.

Brigham & Ehrhardt (2005) in their widely-used corporate finance text point out that the arithmetic average is more consistent with CAPM theory as one of its key underpinning assumptions is that investors are supposed to focus, in their portfolio decisions, upon returns in the next period and the standard deviation of this return. To the extent that this next period is one year, the preference for the arithmetic mean which derives from a set of single one year period returns follows. It is also noteworthy that one of the crucial assumptions inherent in the CAPM is that investors are single-period expected utility of terminal wealth maximizers who choose among alternative portfolios on the basis of each portfolio's expected return and standard deviation.

Brealey, Myers, and Allen (2006) in their leading graduate textbook in corporate finance opt strongly for the arithmetic mean. The authors illustrate the distinction between arithmetic and geometric averages and conclude that arithmetic averages are appropriate when estimating the cost of capital:

> *"The proper uses of arithmetic and compound rates of return from past investments are often misunderstood. Therefore, we call a brief time-out for a clarifying example.*
>
> *Suppose that the price of Big Oil's common stock is \$100. There is an equal chance that at the end of the year the stock will be worth \$90, \$110, or \$130. Therefore, the return could be −10 percent, +10 percent or +30 percent (we assume that Big Oil does not pay a dividend). The expected return is 1/3(-10+10+30)= +10 percent.*
>
> *If we run the process in reverse and HQ Distributionunt the expected cash flow by the expected rate of return, we obtain the value of Big Oil's stock:*
>
> $$PV = \frac{110}{1.10} = \$100$$
>
> *The expected return of 10 percent is therefore the correct rate at which to discount the expected cash flow from Big Oil's stock. It is also the opportunity cost of capital for investments which have the same degree of risk as Big Oil.*
>
> *Now suppose that we observe the returns on Big Oil stock over a large number of years. If the odds are unchanged, the return will be −10 percent in a third of the years, +10 percent in a further third, and +30 percent in the remaining years. The arithmetic average of these yearly returns is*
>
> $$\frac{-10 + 10 + 30}{3} = +10\%$$
>
> *Thus the arithmetic average of the returns correctly measures the opportunity cost of capital for investments of similar risk to Big Oil stock.*

The average compound annual return on Big Oil stock would be

$$(.9 \times 1.1 \times 1.3)^{1/3} - 1 = .088, \text{ or } 8.8\%$$

less than the opportunity cost of capital. Investors would not be willing to invest in a project that offered an 8.8 percent expected return if they could get an expected return of 10 percent in the capital markets. The net present value of such a project would be

$$NPV = -100 + \frac{108.8}{1.1} = -1.1$$

Moral: If the cost of capital is estimated from historical returns or risk premiums, use arithmetic averages, not compound annual rates of return (geometric averages)."

(Richard A. Brealey, Stewart C. Myers, and Paul Allen, *Principles of Corporate Finance*, 8th Edition, Irwin McGraw-Hill, 2006, page 156-7.)

The widely-cited Ibbotson & Associates publication also contains a detailed and rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital[1].

"The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return."

"The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods.

"The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values."

In their widely publicized research on the market risk premium, Dimson, Marsh and Staunton (2002) state

[1] Ibbotson Associates, Stocks Bonds Bills and Inflation, Valuation Edition 2005 Yearbook, page 75.

> *"The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and –20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since (1 + 25/100) x (1 – 20/100) – 1 = 0. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.*
>
> *To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.015 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 x ½ + $0.80 x ½ = $1.00. If there were a sequence of equally likely returns of +25 and –20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is required to compensate for the year-to-year volatility of returns."*

Lastly, on the practical side, Bruner, Eades, Harris, and Higgins (1998) found that 71% of the texts and tradebooks in their extensive survey of practice supported use of an arithmetic mean for estimation of the cost of equity.

Mean Reversion Argument

Some academics have argued that if stock returns were expected to revert to a trend, this would suggest the use of a geometric mean since the geometric mean is, by definition, an estimate of a smoothed long run trend increment. These same academics have argued that the historical estimate of the market risk premium ("MRP") is upward-biased by the buoyant performance of the stock market prior to 2002, and because of the extraordinary and unusually high realized MRPs in those years, investors expect a return to lower MRPs in the future, bringing the average MPR to a more "normal" level.

The presence or absence of mean reversion is an empirical issue. The empirical findings are weak and highly contradictory; the empirical evidence is inconclusive and unconvincing, certainly not enough to support the "mean reversion" hypothesis. The weight of the empirical evidence on this issue is that the more sophisticated tests of mean reversion in the MRP demonstrate that the realized MRP over the last 75 years or so was almost perfectly free of mean reversion, and had no statistically identifiable time trend. It is also noteworthy that most of these studies were performed prior to the stock market's debacle in 2000-2002, years of extraordinary and unusually low realized MRPs. The stock's market dismal performance of 2000-2002 has certainly taken the wind out of the mean reversion school's sails.

An examination of historical MRPs reveals that the MRP is random with no observable pattern and. To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, one should expect the equity risk premium to remain at its historical mean. Therefore, the best estimate of the future risk premium is the historical mean.

Ibbotson Associates (2005) find no evidence that the market price of risk or the amount of risk in common stocks has changed over time:

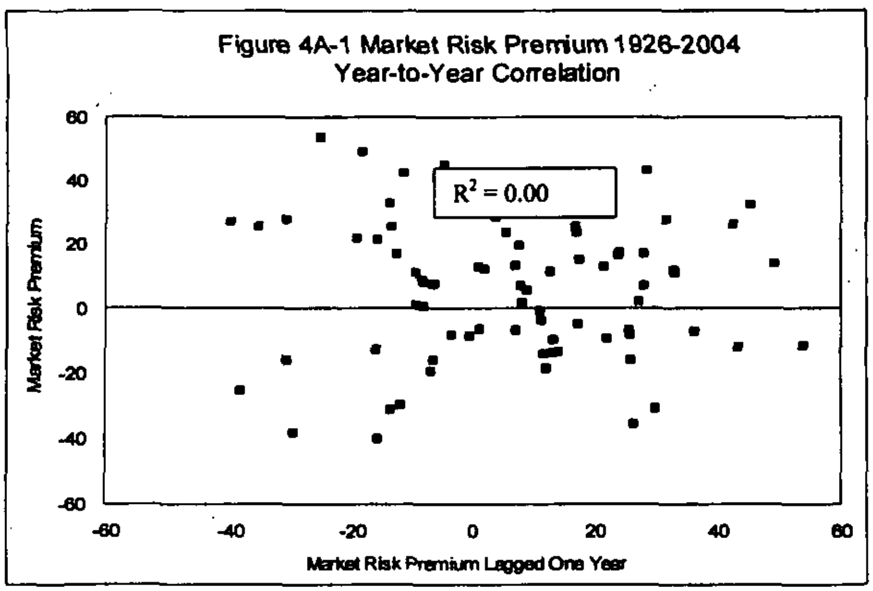
> *"Our own empirical evidence suggests that the yearly difference between the stock market total return and the U.S. Treasury bond income return in any particular year is random........there is no discernable pattern in the realized equity risk premium."* (Ibbotson Associates, Stocks Bonds Bills and Inflation, Valuation Edition 2005 Yearbook, pages 74-75)

In statistical parlance, there is no significant serial correlation in successive annual market risk premiums, that is, no trend. Ibbotson Associates go on to state that it is reasonable to assume that these quantities will remain stable in the future (Id.):

> *"The best estimate of the expected value of a variable that has behaved randomly in the past is the average (or arithmetic mean) of its past values."* (Ibbotson Associates, Stocks Bonds Bills and Inflation, Valuation Edition 2004 Yearbook, page 75)

Nowhere is it suggested by Ibbotson Associates that the market risk premium has declined over time.

Because there is little evidence that the MRP has changed over time, it is reasonable to assume that these quantities will remain stable in the future. Figure 4A-1 below shows the relationship, or the lack of relationship, between year-to-year MRP's reported in the Ibbotson Associates Valuation yearbook, 2005 edition for the 1926-2004 period. The relationship is virtually absent, as indicated by the low R^2 of zero between successive MRPs. In other words, there is no history in successive MRPs as indicated by the zero serial correlation coefficient.



In short, the determination of the cost of capital with the CAPM requires an unbiased estimate of the expected annual return. The expected arithmetic return provides the appropriate measure for this purpose.

Formal Demonstration

This section shows why arithmetic rather than geometric means should be used for forecasting, discounting, and estimating the cost of capital[2]. By definition, the cost of equity capital is the annual discount rate that equates the discounted value of expected future cash flows (from dividends and the sale of the stock at the end of the investor's investment horizon) to the current market price of a share in the firm. The discount rate that equates the discounted value of future expected dividends and the end of period expected stock price to the current stock price is a prospective arithmetic, rather than a prospective geometric mean rate of return. Since future dividends and stock prices cannot be predicted with certainty, the "expected" annual rate of return that investors require is an average "target" percentage rate around which the actual, year-by-year returns will vary. This target rate is, in effect, an arithmetic average.

A numerical illustration will clarify this important point. Consider a non-dividend paying stock trading for $100 which has, in every year, an equal chance of appreciating by 20% or declining by 10%. Thus, after one year, there is an equal chance that the stock's price will be $120 and an equal chance the price will be $90. Figure 4A-2 presents all possible eventualities after two periods have elapsed (the rates of return are presented at the end of the lines in the diagram).

The possible stock prices are shown in the Table 2.

TABLE 2
STOCK PRICES AFTER TWO PERIODS

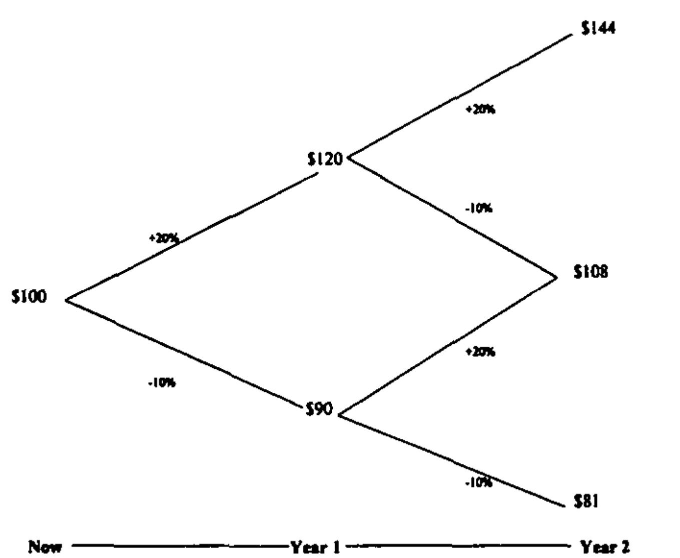
Price	Chance
$144	1 chance in 4
$108	2 chances in 4
$81	1 chance in 4

The expected future stock price after two periods is then:

$$1/4\ (\$144) + 2/4\ (\$108) + 1/4\ (\$81) = \$110.25$$

[2] This section is adapted from a similar treatments and demonstration in Brealey, Myers, and Allen (2006) and Ibbotson Associates (2005).

Figure 4A-2
Possible Stock Prices



The cost of equity capital is calculated as the discount rate that equates the present value of the future expected cash flows to the current stock price. In the present simple example, the only cash flow is the gain from selling the stock after two periods have elapsed. Thus, using the expected stock price of $110.25 calculated above, the expected rate of return is that r, which solves the following equation:

$$\text{Current Stock Price} = \frac{\text{Expected Stock price}}{(1+r)^2}$$

The factor $(1 + r)^2$ discounts the expected stock price to the present. Substituting the numerical values, we have:

$$\$100 = \frac{\$100.25}{(1+r)^2}$$

$$r = 5\%$$

Thus, the cost of equity capital is 5%. This 5% cost of equity capital is equal to the prospective arithmetic mean rate of return, which is the probability-weighted average single period rate of return on equity. Since in every period there is an equal chance that the stock's return will be 20% or -10%, the probability-weighted average is:

$$1/2\,(20\%) + 1/2\,(-10\%) = 5\%$$

However, the 5% cost of equity capital is not equal to the prospective geometric mean rate of return, which is a probability-weighted average of the possible compounded rates of return over the two periods. Now consider the prospective geometric mean rate of return. Table 3 shows the possible compounded rates of return over two periods, and the probability of each.

TABLE 3
STOCK PRICES AND RETURNS AFTER TWO PERIODS

Price	Chance	Compounded Return
$144	1 chance in 4	20.00%
$108	2 chances in 4	3.92%
$81	1 chance in 4	-10.00%

Thus, the prospective geometric mean rate of return is:

$$1/4\ (20\%) = 2/4\ (3.92\%) + 1/4\ (-10\%) = 4.46\%$$

This return is not equal to the 5% cost of equity capital.

The example can easily be extended to include the case of a dividend-paying company and reached the same conclusion: the implied discount rate calculated in the DCF model is an expected arithmetic rather than an expected geometric mean rate of return.

The foregoing analysis shows that it is erroneous to use a prospective multi-year geometric mean rate of return as a "target" rate of return for each year of the period. If, for example, investors currently require an expected future rate of return on an investment of 13% each year, then 13% is the appropriate annual rate of return on equity for ratemaking purposes. Consequently, in using a risk premium approach for the purposes of rate of return regulation, the single-year annual required rate of return should be estimated using arithmetic mean risk premiums.

It should be pointed out that the use of the arithmetic mean does not imply an investment holding period of one year. Rather, it is premised on the uncertainty with respect to each year's return during the holding period, however how many years that may be. When computing the arithmetic average of historic annual returns in order to calculate the average return (expected value of the return), every achieved return outcome is one possible future outcome for each year the security will be held. Each historic return has an equal probability of occurring during each year of the holding period. The resulting expected value of the risk premium is the arithmetic average of all of the past premiums considered, regardless of the length of the expected holding period.

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REBUTTAL TESTIMONY OF
TAYNE S. Y. SEKIMURA

FINANCIAL VICE PRESIDENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Rate of Return on Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Tayne S. Y. Sekimura and I am the Financial Vice President of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company"). My business address is 900 Richards Street, Honolulu, Hawaii, 96813.

Q. Have you previously testified in this proceeding on the return on rate base?

A. Yes, I have presented direct testimony as HELCO T-18 and supplemental testimony as HELCO ST-18 and supporting exhibits and workpapers.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to address the following:

1. Present the Company's updated composite cost of capital which includes:
    a. The average 2006 test year based on 2006 recorded balances;
    b. Explanation of the ratemaking treatment of the December 31, 2006 accumulated other comprehensive income ("AOCI") charges to equity for the defined-benefit pension and postretirement benefits other than pensions ("OPEB") plans; and
    c. Updated financial ratio calculations.
2. Address the settlement agreement with the Consumer Advocate and the Consumer Advocate's testimony regarding:
    a. The Company's Energy Cost Adjustment Clause ("ECAC");
    b. Cost of capital and financial ratios based on the terms of the settlement agreement with the Consumer Advocate;
    c. Keahole writedown;
    d. The Consumer Advocate's proposed pension tracking mechanism;
    e. HELCO's proposal for an OPEB tracking mechanism which is patterned

after the Consumer Advocate's proposed pension tracking mechanism;

f. Business risks and the related impact on return on equity;

g. Adjustment to cost of common equity for HELCO's higher risks;

h. Risk of rate base disallowances of construction costs; and

i. The Consumer Advocate's financial ratio calculations.

UPDATED COMPOSITE COST OF CAPITAL

Q. What is HELCO's updated composite cost of capital for test year 2006?

A. HELCO's updated composite cost of capital is 8.61% as shown in HELCO-R-1801.

Q. What updates have you made to the cost of capital calculation?

A. The cost of capital filed in direct testimony was revised to reflect the following changes:

1. Updated the capitalization balances to reflect December 31, 2006 recorded. This changed the short-term borrowing, long-term borrowing, taxable debt, and common equity amounts. Since these amounts changed, the proportions of all components of cost of capital changed.
2. Updated the long-term debt earnings requirement based on 2006 recorded.
3. For ratemaking purposes, restored common equity for the AOCI charges related to pension and OPEB plans as of December 31, 2006.

These changes are shown in HELCO-R-1801, HELCO-R-1802, HELCO-R-1803, HELCO-R-1804 and the related workpapers.

Short-Term Borrowing

Q. What is the revised average short-term borrowing balance for test year 2006?

A. The average short-term borrowing balance of $50 million, which is higher than the $29 million presented in direct testimony, is shown on HELCO-R-1802.

Q. Why did the short-term borrowing balance change?

A. The average short-term borrowing balance increased because the 2006 year end recorded short-term borrowing balance is higher than the 2006 year end forecast presented in direct testimony. This was primarily due to the level of capital expenditures which the Company had anticipated funding with a taxable debt issuance. Because the taxable debt was not issued in 2006, cash needs were instead financed with short-term borrowings.

Q. What is the revised estimated cost of short-term borrowings for test year 2006?

A. The 5% estimated cost of short-term borrowings presented in direct testimony is still reasonable in light of the 5.18%[1] experienced in 2006. Therefore, no revisions were made to the estimated cost of short-term borrowings for the test year 2006.

Long-Term Borrowing

Q. What is the revised average long-term borrowing balance for test year 2006?

A. The average long-term borrowing balance, shown on HELCO-R-1803, is $117 million, which is slightly lower than the estimate presented in direct testimony.

Q. What adjustments contributed to the change in the long-term borrowing balance?

A. Changes to the long-term borrowing balance are attributable to the 2006 recorded unamortized cost related to the Syndicated Credit Facility ("SCF") and unamortized issuance cost related to the revenue bond issuance that the Company is anticipating in 2007. HELCO's proposal to recover the unamortized SCF cost through the cost of capital calculation for ratemaking was discussed in HELCO's response to CA-IR-448. The unamortized balances and calculations are shown on

[1] 5.18% is the 2006 average monthly rate on HELCO's short-term borrowings. The monthly rates on HELCO's short-term borrowings are derived from HECO's weighted average commercial paper borrowing rate for that corresponding month.

HELCO-R-1803 and HELCO-RWP-1803.

Q. What is the revised estimated effective cost of long-term borrowings for test year 2006?

A. The Company has revised the estimated effective cost of long-term borrowings for the test year 2006 to 5.92% from the 5.90% presented in direct testimony.

Q. Why did the effective cost of long-term borrowings increase?

A. The increase in the effective cost of long-term borrowings is due to an increase in the annual requirement resulting from the annual amortization of the SCF cost and a decrease in the average long-term debt balance as a result of the 2006 recorded unamortized issuance costs. The calculation of the effective rate is shown on HELCO-R-1803.

<u>Taxable Debt</u>

Q. Why was the taxable debt eliminated from the cost of capital calculation?

A. HELCO did not issue the taxable debt it had planned to issue in 2006. Therefore, the taxable debt was eliminated from the cost of capital calculation.

<u>Common Equity and Restoration of AOCI Charges</u>

Q. What is the revised average common equity balance for test year 2006?

A. The calculation of the average common equity balance of $192 million, which is slightly lower than the estimate presented in direct testimony, is shown on HELCO-R-1804.

Q. Why did the average common equity balance change?

A. The change in the common equity balance is due to the 2006 recorded change in retained earnings.

Q. What are the AOCI charges reflected in HELCO-R-1804?

A. Generally accepted accounting standards prescribe that certain situations result in charges to common equity, net of taxes, which are not reflected on the Company's income statement. These charges are made to an equity account entitled "accumulated other comprehensive income." In 2006, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)" ("SFAS 158"). As discussed by Mr. Fujioka in HELCO RT-9, SFAS 158 changed the criteria which trigger AOCI charges for defined-benefit pension and OPEB plans.

Q. Has the Company incurred any AOCI charges to equity?

A. Yes. For financial statement reporting purposes, the Company incurred AOCI charges related to pension and OPEB plans as of December 31, 2006.

Q. How does the Company propose to treat the AOCI charges for ratemaking purposes?

A. For ratemaking purposes, the Company has restored common equity for the AOCI charges, as shown on HELCO-R-1804. As discussed by Mr. Fujioka in HELCO RT-9, the AOCI charges are included (net of the pension and OPEB liabilities) in rate base.

Q. Why is it proper to restore common equity for the AOCI charges for ratemaking purposes?

A. Shareholders have invested funds that exclude the deduction from (or addition to) equity for financial statement purposes for AOCI and should be allowed a return on invested funds. Therefore, the ratemaking cost of capital should be based on the equity balance excluding the deduction (or addition) for AOCI. If the AOCI adjustment is included in ratemaking equity, the equity ratemaking balance will fluctuate (higher or lower) depending primarily on the market value of the pension and OPEB funds. On Exhibit HELCO-R-1805, I provide an illustration of what the pension portion of the AOCI charge or credit to equity would have been in the period 1995 to 2006 if SFAS 158 had been in effect. As you can see, AOCI would have increased equity in 1996 through 2001. In some of those years, the increase would have been significant.

Q. Does the Commission's ruling in Docket No. 05-0310 impact the ratemaking treatment of the AOCI charge?

A. No. In Docket No. 05-0310, the Commission ruled that the Company could not record a regulatory asset for the amounts which would otherwise be charged to AOCI. The Commission did not address the ratemaking treatment of the AOCI charge.

Q. Do the pension and OPEB tracking mechanisms discussed later in your testimony impact the ratemaking treatment of the AOCI charges?

A. Yes. The pension and OPEB tracking mechanisms that are discussed later in my testimony would eliminate the AOCI charges for both book and ratemaking purposes.

<u>Revised Capital Structure</u>

Q. What is the revised capital structure?

A. As a result of the changes just described, a test year capital structure consisting of 13.24% short-tem debt, 31.37% long-term debt, 2.45% hybrid securities, 1.75% cumulative preferred stock, and 51.19% common equity is appropriate.

<u>Updated Financial Ratios</u>

Q. Have you updated the projected financial ratios for the test year as presented in your direct testimony?

A. Yes. We have updated the financial ratio calculations in HELCO-R-1806. There are two sets of ratios. One set is based on HELCO receiving rate relief and earning an 11.25% return on common equity. The other set is based on no rate relief.

Q. What are the implications of the updated ratios?

A. A comparison of HELCO's projected ratios to the financial guidelines applicable to HELCO is shown on HELCO-R-1806 (pages 3 and 4). Based on a current S&P business profile of "5", without rate relief:

- the funds from operations/interest coverage ratio is indicative of a BBB rating (3.5 in BBB range of 2.8-3.8),
- the funds from operations/total debt ratio is indicative of a BBB rating (16 in BBB range of 15-22), and
- the total debt/total capital ratio is indicative of a BBB rating (55 in BBB range of 60-50).

With rate relief:

- the funds from operations/interest coverage ratio is indicative of an AA rating (4.6 in AA range of 4.5-5.5),
- the funds from operations/total debt ratio is indicative of an A rating (23 in A range of 22-30), and
- no change to the total debt/total capital ratio, which is indicative of a BBB rating (55 in BBB range of 60-50).

SETTLEMENT AGREEMENT AND CONSUMER ADVOCATE POSITIONS

Energy Cost Adjustment Clause ("ECAC")

Q. Does the Consumer Advocate support the continuation of the existing ECAC?

A. Yes. The Consumer Advocate acknowledges the benefits to ratepayers of the existing ECAC and supports its continuation. See testimonies of Mr. Brosch in

CA-T-1, pages 22-23, and Mr. Herz in CA-T-2, page 64.

<u>Cost of Capital and Financial Ratios Based on the Settlement Agreement</u>

Q. Are the parties in agreement on the capital structure for ratemaking purposes?

A. Yes. As a result of settlement discussions, the Consumer Advocate and the Company agree to use a capital structure of 13.24% short-term debt, 31.37% long-term debt, 2.45% hybrid securities, 1.75% preferred stock and 51.19% common equity.

The Consumer Advocate's capital structure in its direct testimony mirrored the Company's direct testimony capital structure which was developed prior to the Company knowing that AOCI charges would apply as of December 31, 2006. Thus, it was not clear whether the Consumer Advocate's direct testimony capital structure considered HELCO's actual AOCI charges as of December 31, 2006 or the restoration to equity for the actual AOCI charges. In settlement discussions, the Company provided the Consumer Advocate with an explanation of the AOCI restoration. In calculating the average common equity balance for the 2006 test year, the Consumer Advocate has agreed to use the December 31, 2006 balance with the AOCI charges restored for ratemaking purposes.

Q. Are the parties in agreement on the cost of the various components of the capital structure other than the cost of common equity?

A. The parties agreed on the cost of short-term debt of 5.00%, cost of hybrid securities of 7.50% and cost of preferred stock of 8.37%. As indicated earlier in my testimony, the long-term debt rate was revised from the 5.90% presented in direct testimony to 5.92%. HELCO's proposal to recover the unamortized SCF cost through the cost of capital calculation for ratemaking was discussed in HELCO's response to CA-IR-448. However, the Consumer Advocate's testimony was based on the Company's direct testimony and did not reflect this update. In settlement discussions, the Consumer Advocate indicated that this change in long-term debt rate is acceptable if the increase was attributable to actual transaction costs incurred. The increase in the effective cost of long-term borrowings is due to an increase in the annual requirement resulting from the annual amortization of HELCO's share of the SCF cost and a decrease in the average long-term debt balance as a result of the 2006 recorded unamortized issuance costs. The calculation of the effective rate is shown on HELCO-R-1803. Therefore, the long-term debt rate is agreed upon at 5.92%.

Q. Have the parties reached agreement regarding the cost of common equity?

A. Yes. In the settlement agreement, the parties agreed to a cost of common equity of 10.7% as presented on HELCO-R-1801. In direct testimony, the Company requested a cost of common equity of 11.25% as presented by Dr. Morin in HELCO T-17. Dr. Morin maintains his cost of equity in his rebuttal testimony in HELCO RT-17 at 11.25%. The Consumer Advocate's witness, Mr. Parcell, recommends a cost of equity rate of 9.5% to 10.25%.

Q. Why did the Company agree to settle the cost of common equity at 10.7% when it maintains that a return on common equity of 11.25% is necessary?

A. The agreement to settle the cost of common equity at 10.7% must be viewed in the context of the settlement agreement in total. As Mr. Lee explains in HELCO RT-1, the settlement agreement balances the interests of all parties, including ratepayers and investors. The cost of common equity of 10.7% included in the settlement agreement was necessary to reach settlement of all issues.

Q. Have you calculated the projected financial ratios for the test year based on the terms of the settlement?

A. Yes. The financial ratio calculations based on the settlement terms appear on HELCO-R-1806, pages 1 and 2. There are two sets of ratios. One set is based on HELCO receiving rate relief and earning a 10.7% return on common equity. The other set is based on no rate relief.

Q. What are the implications of the ratios based on the settlement agreement?

A. Based on a current S&P business profile of "5", with rate relief based on the terms of the settlement (See HELCO-R-1806, pages 1 and 2), the resulting ratios (compared to the ratios based on HELCO's updated cost of capital calculated prior to the settlement and shown in HELCO-R-1806, pages 3 and 4) indicate the following:

- the funds from operations/interest coverage ratio is slightly lower and is indicative of a AA/A rating (4.45 in AA range of 4.5-5.5; A range of 3.8-4.5),
- the funds from operations/total debt ratio is slightly lower and is indicative of an A/BBB rating (22 in A range of 22-30; BBB range of 15-22), and
- there is no change to the total debt/total capital ratio, which is indicative of a BBB rating (55 in BBB range of 60-50).

Keahole CT-4 and CT-5 Writedown

Q. What have the Parties agreed to with respect to Keahole CT-4 and CT-5?

A. The settlement reflects a write down of $12,898,000 of gross plant in service (or $12,000,000 net of accumulated depreciation) and $898,000 of accumulated depreciation associated with the CT-4 and CT-5 units at the Keahole generating station, with associated reductions in depreciation expense, accumulated deferred income taxes, unamortized state investment tax credit ("ITC") and amortization of state ITC.

Q. What was the Consumer Advocate's position with respect to Keahole CT-4 and

CT-5?

A. As explained by Mr. Fujioka in HELCO RT-9, the Consumer Advocate recommended that only $7.3 million of allowance for funds used during construction ("AFUDC") be recovered which compares to the $21.7 million that HELCO accrued. Stated another way, the Consumer Advocate proposed a disallowance of $14.4 million ($21.7 million minus $7.3 million) of AFUDC, before taking into account the offset for accumulated depreciation. As explained by Mr. Fujioka in HELCO RT-9, approximately $1.5 million of the $14.4 million was previously approved by the Commission to be included in rate base when the Commission included Pre-PSD facilities in rate base in HELCO's 2000 test year rate case (Decision and Order No. 18365 dated February 8, 2001 in Docket No. 99-0207). The Consumer Advocate also proposed that certain costs for land use permitting and related litigation, noise abatement measures, landscaping, and land rezoning totaling approximately $9.6 million be disallowed (before accumulated depreciation offset). See Exhibit CA-101 Schedule B-8.

Q. What is the Company's overall position with respect to the above Consumer Advocate proposals?

A. As covered by other Company witnesses, the costs included represent costs associated with facilities that are used or useful and/or expenses that were prudently incurred by the Company to provide electric service. Therefore, the Commission should include such costs in its determination of revenue requirements for the 2006 test year. Costs that are prudently incurred by HELCO to provide electric service should be recovered from ratepayers.

The rate base calculation used in Hawaii results in a net rate base which approximately equals the amount of money committed by investors to plant in service. Rate base exclusions produce a net rate base which is less than the amount of investors' funds committed to plant in service. If the investment is not in the rate base or in construction work in progress (where the investors are compensated through AFUDC), there is currently no mechanism to earn a return on that investment. The inability to earn a return on part of the money invested would make it impossible (without offsetting circumstances of some sort) for the investors to earn the overall rate of return determined fair and reasonable by the Commission. This will ultimately lead to investors requiring higher returns as a result of the risk of earning lower returns due to disallowances.

Q. Why did the Parties agree to settle this issue?

A. Mr. Lee addresses this from HELCO's perspective in HELCO RT-1. Both parties recognized that hearings on the issue of the Keahole CT-4 and CT-5 would be long, arduous, and drain resources that they could otherwise put to more productive use. Many of the disputed items result from the specific situation and circumstances surrounding CT-4 and CT-5 rather than from broader policy issues for which hearings might be more appropriate or necessary. HELCO decided that all things considered, it would be best to accept the settlement, bring closure to the Keahole matter and allow HELCO to focus its attention on meeting the challenges of the future and providing efficient, reliable service to its customers.

Q. How will the settlement impact HELCO investors?

A. As a result of the settlement agreement, full recovery of Keahole CT-4 and CT-5 will no longer be deemed probable and the Company's net investment in Keahole CT-4 and CT-5 will be written down by approximately $12 million. HELCO's parent company, HECO, will issue a disclosure of the settlement in accordance with the requirements of the Securities and Exchange Commission. This writedown will result in an after-tax charge to net income in the first quarter of 2007 of approximately $7 million.

Investors in an electric utility, such as HELCO, need to have a realistic chance to earn the return determined fair and reasonable on their total investment in HELCO's electric utility business. Investors expect the Company to be able to recover prudently incurred costs from its customers. Exclusion of such costs from revenue requirements reduce income and diminish the ability of investors to earn the fair rate of return on equity.

However, acceptance of the settlement agreement by the Commission will eliminate the ongoing uncertainty of the ratemaking treatment of the Company's investment in Keahole CT-4 and CT-5. Further, timely rate relief will allow the Company the opportunity to improve earnings going forward. First quarter 2007 HECO consolidated earnings will be severely impacted. However, because this action is a one-time event relating to the unique situation at Keahole, the writedown relating to CT-4 and CT-5 may not significantly adversely impact investors' long-term perceptions of HELCO and its utility affiliates.

If, however, investors perceive the writedown as part of an overall reduction in regulatory support for prudent utility investments, the Company's business risk profile will increase. If investors perceive higher risks associated with making utility investments, this will increase the Company's cost of capital over the long term.

<u>Consumer Advocate's Alternative Proposal – Pension Tracking Mechanism</u>

Q. Does the Consumer Advocate accept the Company's pension cost estimate, pension asset in rate base, and restoration of equity for pension amount which was charged to AOCI?

A. The Consumer Advocate accepts the Company's pension cost estimate. See Ms. Price's testimony in HELCO RT-10. The Consumer Advocate also accepts the pension asset in rate base. As discussed by Mr. Fujioka in HELCO RT-9, the Company does not agree with the Consumer Advocate's method to determine when it was appropriate to include the pension asset in rate base. The Company has supported inclusion of the pension asset in rate base in Mr. Fujioka's direct and rebuttal testimonies (HELCO T-9 and HELCO RT-9) as well as in my rebuttal testimony in Hawaiian Electric Company, Inc. ("HECO")'s 2005 test year rate case (Docket No. 04-0113, HECO RT-16), Ms. Nanbu's direct testimony in HECO's 2007 test year rate case (Docket No. 2006-0386, HECO T-10) and Mr. Matsunaga's testimony in Maui Electric Company, Ltd. ("MECO")'s 2007 test year rate case (Docket No. 2006-0387, MECO T-9). As I mentioned earlier in my testimony, the Consumer Advocate accepts the restoration of equity for the pension and OPEB AOCI charges. The Parties agreed to the pension expense, pension asset in rate base, and AOCI restoration to calculate revenue requirements in this rate case; in addition, however, the Consumer Advocate proposed an alternative pension tracking mechanism.

Q. Please briefly describe the Consumer Advocate's pension tracking mechanism.

A. In CA-T-3, Mr. Carver presents the Consumer Advocate's alternative pension tracking mechanism. Under the alternative tracking mechanism, an amount is identified in each rate case as pension costs in rates. Once new rates are effective, and until rates are changed in a subsequent rate case, the amount of pension cost in rates is separately tracked. The mechanism requires that the Company make fund contributions at the actuarially calculated net periodic pension cost ("NPPC") as determined under generally accepted accounting principles subject to certain exceptions.[2] (Currently SFAS No. 87, "Employers' Accounting for Pensions", is the accounting guidance that addresses the calculation of NPPC.) At each rate case, the cumulative amount of pension cost in rates since the last rate change is compared to the cumulative amount of contributions to the pension fund. This net amount is an addition (if the cumulative fund contributions exceed the cumulative amount in rates) or deduction (if the cumulative amount in rates exceeds the cumulative fund contributions) in the calculation of rate base. The test year ending pension balance in rate base is then amortized over five years beginning when new rates are effective. The pension tracking mechanism would also allow the Company to reverse the pension AOCI charge to equity and create a regulatory asset for financial statement purposes.

Q. How would the pension cost in rates be determined?

A. The pension cost in rates would be the test year NPPC plus or minus the amortization of the ending pension amount in rate base. If cumulative contributions have exceeded the cumulative pension amount in rates (an addition to rate base), the amortization would be an addition to NPPC (i.e., future rates will be relatively higher). If cumulative pension amount in rates have exceeded cumulative contributions (a deduction in rate base), the amortization would be a deduction from NPPC (i.e., future rates will be relatively lower).

Q. Does the Company accept the Consumer Advocate's alternative pension tracking mechanism?

A. Yes, the Company and the Consumer Advocate have reached agreement on the pension tracking mechanism proposed by the Consumer Advocate. The Company

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[2] The pension funding is further restricted to the ERISA minimum and tax deductible maximum. When NPPC is negative, there is no funding requirement.

proposed certain modifications to the tracking mechanism proposed by the Consumer Advocate to allow the Company greater flexibility for funding more than NPPC for certain specified reasons. In addition, the Company proposed language to clarify how the tracking mechanism will be implemented. Exhibits HELCO-R-1808 and HELCO-R-1809 reflect CA-304 and CA-305, respectively, modified for changes which have been agreed to by the Company and the Consumer Advocate.

Q. Do the revenue requirements filed in this rebuttal testimony, the settlement agreement, and the Statement of Probable Entitlement assume that the pension tracking mechanism is adopted?

A. Yes. The revenue requirements filed in this rebuttal testimony, the settlement agreement, and the Statement of Probable Entitlement all reflect adoption of the pension tracking mechanism. The revenue requirements include $2,554,000, which is the amortization of the ending pension asset balance (ending pension asset of $12,771,000 divided by 5), in addition to the test year NPPC of $2,744,000. These amounts are reflected in the testimonies of Mr. Fujioka in HELCO RT-9 and Ms. Price in HELCO RT-10. In addition, however, an alternative revenue requirement calculation without the pension tracking mechanism being adopted in the interim decision and order, and therefore without the pension asset amortization, is filed with the Statement of Probable Entitlement.

Q. How does the adoption of the pension tracking mechanism impact prior pension cost recovery?

A. The pension tracking mechanism does not apply retroactively and does not impact prior pension costs. The pension tracking mechanism applies prospectively from the date that the Commission issues an order which: (1) approves the adoption of the pension tracking mechanism and (2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates. Until the pension tracking mechanism is adopted, ratemaking treatment of pension is based on the past practices of this Commission which treat pension expense in generally the same manner as other expenses which do not have special ratemaking treatment. In contrast, for example, fuel, Integrated Resource Planning, and Demand Side Management expenses have special ratemaking treatment based on specific Commission orders. HECO's consistent ratemaking treatment of pension costs in the past and the prohibition against retroactive ratemaking to pension were discussed in HECO's 2005 test year rate case (Docket No.04-0113) Opening Brief dated December 2, 2005 (pages 106 to 110) and Reply Brief of HECO dated December 19, 2005 (pages 5 to 6 and 14 to 16). Pension costs will not have special ratemaking treatment until the pension tracking mechanism is adopted by the Commission.

Q. When would the pension tracking mechanism be implemented?

A. The pension tracking mechanism would be effective on the date which the Commission issues an order which: (1) approves the adoption of the pension tracking mechanism and (2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates. If the Commission's interim rate order in this docket includes: (1) approval to adopt the pension tracking mechanism and (2) interim rates that explicitly incorporate the test year NPPC of \$2,744,000 and amortization of the pension asset of \$2,554,000 (as described in the testimony of Ms. Price in HELCO RT-10 and Mr. Fujioka in HELCO RT-9), the pension tracking mechanism would be adopted as of the date of the interim rate order.

HELCO's Proposal for a Postretirement Benefits Other Than Pensions ("OPEB") Tracking Mechanism

Q. Please describe HELCO's proposal for an OPEB tracking mechanism.

A. HELCO has proposed a tracking mechanism for OPEB, which mirrors the pension tracking mechanism proposed by the Consumer Advocate. The proposed OPEB tracking mechanism, which incorporates revisions suggested by the Consumer Advocate, and comments further explaining the mechanism are provided on Exhibits HELCO-R-1810 and HELCO-R-1811.

Q. Does the Consumer Advocate accept the OPEB tracking mechanism?

A. Yes.

Q. How would implementation of the OPEB tracking mechanism impact revenue requirements in this case?

A. The adoption of the OPEB tracking mechanism would not impact revenue requirements in this docket. However, the OPEB tracking mechanism specifies ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of net periodic benefit costs ("NPBC") established in this rate case and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized. Adoption of the OPEB tracking mechanism would also allow the Company to reverse the OPEB AOCI charge to equity and create a regulatory asset for financial statement purposes.

Q. When would the OPEB tracking mechanism be implemented?

A. The OPEB tracking mechanism would be effective on the date which the Commission issues an order which approves its adoption. If the Commission's interim rate order in this docket includes: (1) approval to adopt the OPEB tracking mechanism and (2) interim rates that explicitly incorporate the test year OPEB costs of $1,530,400[3] (see testimony of Ms. Price in HELCO RT-10), the OPEB tracking mechanism would be adopted as of the date of the interim rate order.

Adjustment to Cost of Common Equity for HELCO's Higher Risks

Q. Do you have any comments on Mr. Parcell's statement on pages 60 through 62 of CA-T-4 that current circumstances do not warrant the upward adjustment of 35 basis points to HELCO's rate of return on equity, as proposed by Dr. Morin in HELCO T-17?

A. Yes, I do. Although HELCO and the Consumer Advocate have settled on a rate of return on common equity for this rate case, it is necessary for the Company to express its position on this issue in response to Mr. Parcell's arguments to the contrary. Mr. Parcell argues that HELCO's request for a 35 basis point adjustment above the cost of equity for comparison utilities should be denied in this proceeding. However, the market-derived cost of common equity for a group of proxy companies cannot simply be applied to HELCO without further analysis. A comparison must be made of the relative investment risk of HELCO versus that of the proxy companies selected by the experts. When the relative risk comparison is made, it is clear that HELCO has greater investment risk than that of the proxy group of comparable companies. As a result, the cost of common equity for HELCO is greater than the market-derived cost of common equity for such proxy companies.

[3] NPBC of $1,369,800 minus executive life portion of $103,300 plus FAS 106 regulatory asset amortization of $263,900

As Mr. Parcell notes, the Commission in prior Decisions and Orders[3] has recognized that HELCO has greater risks than both the Consumer Advocate's and HELCO's groups of comparable companies. Taking various risk factors into consideration, the Commission determined that an adjustment was necessary to allow for HELCO's greater risks as compared to the comparable companies. In Decision and Order No. 18365 (dated February 8, 2001) in Docket No. 99-0207, HELCO's 2000 test year rate case, the Commission stated:

> "HELCO urges us to consider adjustments to account for its greater risk, relative to the comparable companies. We agree that a risk adjustment is appropriate. HELCO's risk is inherent in its smaller size and is demonstrated by its higher operating ratio, lower quality of earnings, and weak level of internally generated funds for construction. In addition, its substantial purchase power obligations and bond ratings are matters which concern us.
>
> We find unpersuasive the Consumer Advocate's assertions that we need not make any risk adjustments. HELCO is financially weaker and subsequently riskier than all of the proxy groups. Therefore, it is appropriate to make an adjustment for HELCO's risk. Ultimately, both HELCO and its customers benefit when HELCO has sufficient financial integrity to attract capital. Accordingly, we believe that an upward adjustment of 50 basis points is warranted. By this adjustment, the rate of return on common equity rises to 11.5 per cent.
>
> We believe that this rate is supportive of HELCO's financial integrity and will enable HELCO to continue to attract capital."

Mr. Parcell starts his discussion of the reasons for his belief that the upward adjustment is no longer necessary, with a review of the Commission's adjustments. He notes on page 61 of his testimony that, "the impetus for the adjustments occurred during the 1993-1994 time period, as reflected in Commission orders in 1994-1995", during which time HECO, MECO and HELCO were experiencing downgrades of their securities. He also notes that

[3] See Decision and Order No. 18365 in Docket No. 99-0207, Decision and Order No. 15480 in Docket No. 94-0140 and Decision and Order No. 13762 in Docket No. 7764.

during that time period, the Commission's final rate case decisions were awarded at a slower pace. However, he made the same contention in HELCO's 2000 test year rate case (CA-T-13 at 60.), and the Commission explicitly found that an upward adjustment of 50 basis points was warranted, as quoted above.

Mr. Parcell then states that HELCO's financial status has improved and that the Commission's response time for rate cases has improved and that the Hawaii Commission is one of a few commissions to have an "above average" rating by Value Line. He further notes that HELCO's own perceptions of its relative risks have reflected a decline as the request of 35 basis points upward adjustment is lower than any previous Commission award. While we acknowledge that the Commission has been supportive, particularly by granting interim rate relief orders which reduce the negative financial impact of regulatory lag, Mr. Parcell's claim that HELCO's financial status has improved is unfounded. As shown on Exhibit HELCO-R-1807, HELCO's rate of return on rate base and rate of return on equity have steadily declined since 2002.

Many of the factors that adversely impact HELCO's business risk have been recognized by the Commission in prior rate case decisions and continue to apply in this case. They include: (1) HELCO's service territory is geographically isolated; (2) HELCO lacks interties, which precludes the Company from having other utility systems provide reliable backup generation sources; (3) there is a scarcity of generation sites in HELCO's service territory, (4) HELCO purchases a substantial percentage of its power through firm capacity contracts, which impacts HELCO's financial condition; (5) HELCO's service territory is significantly dependent upon tourism; (6) HELCO is significantly dependent on oil for electric generation; and (7) HELCO is a very small company.

Q. Please summarize the Company's position on whether a risk adjustment applies to HELCO.

A. The overall risks for HELCO are greater than for the comparable companies, and therefore an adjustment to the rate of return on common equity is still appropriate. HELCO needs the continuing support of the Commission to help it maintain its credit and to adequately compensate common stock investors – i.e., support demonstrated by the Commission's recognition of HELCO's greater business risks, as evidenced by the Commission's upward adjustment in what it determines to be a fair and reasonable rate of return on common equity for HELCO. Loss of this support would be detrimental in the rating agencies' assessments of the Company's business risks.

The Commission's responsive decisions for HELCO, including the upward adjustment made to the rate of return on common equity, have been important factors in helping HELCO maintain its financial integrity. The timing and adequacy of rate relief (including timely and adequate interim rate relief) affect the business risks of HELCO and are matters of concern to the rating agencies and investors.

Q. Is HELCO suggesting that there should be an adjustment to the 10.7% rate of return on common equity accepted in the settlement agreement?

A. No. HELCO supports the 10.7% rate of return on common equity as part of the global settlement of issues impacting revenue requirements. My testimony is intended to address Mr. Parcell's pre-settlement direct testimony, and not the settlement.

Regulatory Process—Risk of Rate Base Disallowances of Construction Costs

Q. On page 21 of Mr. Parcell's testimony, as part of his discussion regarding the regulatory climate in Hawaii, Mr. Parcell asserts that the regulatory process in Hawaii serves to minimize the risk of rate base disallowances. Mr. Parcell claims that the Commission's procedures which provide opportunities to review and approve expenditures for major construction projects prior to their appearance in a rate case proceeding results in significantly reducing the likelihood of rate base disapproval. He claims this reduces the Company's business risks. Do you have any comments on this?

A. Yes. It is the case that the Commission's prior review of construction projects helps to reduce the Company's business risk. The Commission has permitted the Company's capital expenditures to be included in rate base and has refrained from disallowing items because of changed circumstances. This is helpful in reducing regulatory risk, but does not eliminate it completely. There have been cases where the Companies have had to make substantial commitments of funds prior to Commission approval under paragraph 2.3(g)(2) of General Order No. 7 in order to maintain the schedule for a project essential to reliable service. The ability to move forward on these projects is essential to maintain the Company's obligation to serve, since the Company is not interconnected with other utilities and cannot import power as other utilities can. The writedown related to Keahole CT-4 and CT-5 eliminates the risk mitigation that Mr. Parcell suggests exists and has been factored into his return on equity calculations.

Consumer Advocate's Financial Ratio Calculations

Q. Do you have any comments on CA-414 which Mr. Parcell refers to in his contention that a 9.88% return on common equity (the midpoint of his 9.5% to 10.25% range) will provide sufficient earnings for HELCO to maintain its financial integrity?

A. Yes. On page 48 of his testimony, Mr. Parcell indicates his belief that his cost of capital recommendation provides the Company with a sufficient level of earnings to maintain its financial integrity. Mr. Parcell refers to his pre-tax interest coverage calculation (see CA-414) and indicates that the mid-point of his recommended range produces a coverage level (which he calculates at 3.38 times) which is within the benchmark range for a BBB rated utility (2.4-3.5 times). He also indicates that his calculation of the debt ratio is within the benchmark for an A rated utility (42-50%).

Assuming a 9.88% return on common equity (as noted in CA-414), the Company calculates a pre-tax interest coverage of 3.15 times, vs. the 3.38 times reflected in CA-414, which is within the benchmark range for a BBB rating (2.4-3.5 times). However, the Company does not agree with Mr. Parcell when he states that "the debt ratio (which reflects the capital structure as proposed by the Company) is within that benchmark for an A rated utility." Based on the percentages presented by Mr. Parcell in CA-414, the Company's total debt to total capital ratio is 52.6%, which indicates a BBB rating (53% in BBB range of 60-50%). As noted earlier in testimony under the Updated Financial Ratios section, the Company projects the total debt to total capital ratio for the test year to be indicative of a BBB rating (55% in BBB range of 60-50%).

CONCLUSION

Q. What is your conclusion as to the appropriate rate of return on rate base to use in calculating revenue requirements in this docket?

A. The rate of return on its full rate base should not be less than the Company's composite cost of capital. The settlement agreement, if accepted in total and if used as the basis for an interim rate increase, will provide timely rate relief to the

Company, and should help HELCO to better achieve and maintain financial integrity. The settlement agreement includes a composite cost of capital of 8.33% (Exhibit HELCO-R-1801 page 1), including a rate of return on common equity of 10.7%.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

SETTLEMENT

Hawaii Electric Light Company

Composite Embedded Cost of Capital
Test Year 2006 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	Exhibit Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	R-1802	$ 49,550	13.24%	5.00%	0.66%
Long-Term Debt	R-1803	117,408	31.37%	5.92%	1.86%
Taxable Debt	1804 - no issuance, thus balance is zero.	-	0.00%	6.20%	0.00%
Hybrid Securities	1805	9,152	2.45%	7.50%	0.18%
Preferred Stock	1806	6,563	1.75%	8.37%	0.15%
Common Equity	R-1804	191,544	51.19%	10.70%	5.48%
Total Capitalization		$ 374,216	100.00%		8.33%

Estimated 2006 Test Year Composite Cost of Capital **8.33%**

Totals may not add exactly due to rounding.

Hawaii Electric Light Company

Composite Embedded Cost of Capital
Test Year 2006 Average
($ Thousands)

		(A)	(B) = (A)/Total(A)	(C)	(D) = (B)*(C)
		Capitalization			
	Exhibit Reference	Amount	Percent of Total	Earnings Requirement	Weighted Earnings Requirements
Short-Term Debt	R-1802	$ 49,550	13.24%	5.00%	0.66%
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Taxable Debt	1804 - no issuance, thus balance is zero.	-	0.00%	6.20%	0.00%
Hybrid Securities	1805	9,152	2.45%	7.50%	0.18%
Preferred Stock	1806	6,563	1.75%	8.37%	0.15%
Common Equity	R-1804	191,544	51.19%	11.25%	5.76%
Total Capitalization		$ 374,216	100.00%		8.61%

Estimated 2006 Test Year Composite Cost of Capital **8.61%**

Totals may not add exactly due to rounding.

Hawaii Electric Light Company.

Short-Term Borrowings
Test Year 2006 Average
($ Thousands)

	WP Reference	Total	
Short-Term Borrowings as of December 31, 2005	WP-1802, p.1	49,700	(A)
Short-Term Borrowings as of December 31, 2006 (recorded)		$ 49,400	(B)
Test Year 2006 Average = [(A)+(B)]/2		**$ 49,550**	
Earnings Requirement		5.00%	
Annual Debt Requirement		**$ 2,478**	

Totals may not add exactly due to rounding.

Filename: HELCO-R-1801 to 1804.xls R-1802 STD

Hawaii Electric Light Company

Embedded Cost of Long-Term Debt
Test Year 2006 Average
($ Thousands)

Long-Term Debt	(A) Rate	(B) Net Proceeds	(C) = (A)*(B) Annual Interest	(D) = WP-1803, p.2 and RWP-1803, p.1 Annual Amortization	(E) Annual Insurance Premium	(F) = (C)+(D) + (E) Annual Requirement
Special Purpose Revenue Bonds (Refunded Issue):						
Series 1993	5.45%	$ 20,000	$ 1,090	$ 34		$ 1,124
Series 1996A	6.20%	7,000	434	11		445
Series 1996B	5 7/8%	1,000	59	1	1 *	61
Series 1997A	5.65%	30,000	1,695	33		1,728
Refunding Series 1998A (1982 & 1987)	4.95%	7,200	356	32		389
Refunding Series 1999A (1984)	5.50%	11,400	627	30		657
Refunding Series 1999B (1988)	5.75%	11,000	633	43		676
Refunding Series 1999D (1990A)	6.15%	3,000	185	9		194
Refunding Series 2003A (1990B&C)	4.75%	14,000	665	65		730
Refunding Series 2003B (1992)	5.00%	12,000	600	45		645
Refunding Series 2005A (1995A)	4.80%	5,000	240	20		260
		121,600	6,583	323	1	6,907
Unamortized Costs, Revenue Bonds **		(4,136)				
Unamortized Costs, First Mtg Bonds ***		(9)		19		19
Unamortized Costs, 2007 rev bond issuance		(2)				
Unamortized Costs, SCF ****		(45)		21		21
Test Year 2006 Average		$ 117,408	$ 6,583	$ 363	$ 1	$ 6,947
Effective Rate = Total(E)/Total(B)						5.92%

* Based on 9 basis points annually of outstanding par beginning in 2006, which was footnoted in HELCO-WP-1803, and further discussed in response to CA-IR-448.

** Issuance costs, redemption costs, issuance discounts, and investment income differentials are included in this amount. Refer to WP-1803, p.1 for detail.

*** Unamortized costs relate to HELCO's First Mortgage Bonds which were redeemed. Refer to WP-1803, p.7 for First Mortgage Bonds unamortized costs.

**** Unamortized costs relate to HELCO's share of the costs for the Multi-year Syndicated Credit Facility (SCF). On March 14, 2007, the Commission approved the five-year SCF (see Decision and Order No. 23301, Docket No. 2006-0360). Refer to RWP-1803, p. 1.

Totals may not add exactly due to rounding.

Hawaii Electric Light Company,

Common Equity
2006 Average
($ Thousands)

	WP Reference		BOOK Total	Adjustments for Ratemaking		RATEMAKING Total
Book Common Equity as of December 31, 2005	WP-1807, p.1	$	189,407		$	189,407
Restoration	WP-1807 p.2		-	100		100
Common Equity Investment as of December 31, 2005	(A)		189,407			189,507
2006 recorded Change in Retained Earnings			4,073			4,073
2006 Net AOCI adj related to Qualified Pension, net of tax			(15,141)	15,141		-
2006 Net AOCI adj related to Non-Qualified Pension, net of tax			74	(74)		-
2006 Net AOCI adj related to OPEB, net of tax			(3,336)	3,336		-
2006 Net AOCI adj related to Exec Life, net of tax			22	(22)		-
Common Equity as of December 31, 2006	(B)		175,099			193,580
Test Year 2006 Average = [(A)+(B)]/2					**$**	**191,544**
Book 2006 Average = [(A)+(B)]/2		$	182,253			

Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

PENSION AOCI IF SFAS 158 HAD APPLIED SINCE 1995

1995-2006

($ in thousands)

						ILLUSTRATION ONLY	
Year	Contributions to Trust	NPPC Accrual	Ending Pension Asset Balance before AOCI Adj	PBO at 12/31	MV Plan Assets at 12/31	Asset (Liability) under SFAS 158	Pension AOCI (net of tax)
	A	B	C= Prior C + A - B	D	E	F = E - D	G = (F-C) * (1-tax rate)
1994			-				
1995	1,827	1,827	-	61,469	59,304	(2,165)	(1,323)
1996	2,531	2,531	-	66,937	68,117	1,180	721
1997	2,222	2,222	-	71,781	78,951	7,170	4,380
1998	1,482	1,102	380	79,493	91,278	11,785	6,967
1999	-	468	(88)	68,438	115,197	46,759	28,619
2000	-	(3,107)	3,019	75,493	108,645	33,152	18,408
2001	-	(3,399)	6,418	80,962	93,900	12,938	3,983
2002	-	(2,557)	8,975	92,153	76,759	(15,394)	(14,887)
2003	3,621	1,498	11,098	105,975	93,547	(12,428)	(14,372)
2004	4,868	76	15,890	114,468	102,347	(12,121)	(17,112)
2005	500	875	15,515	122,938	105,338	(17,600)	(20,230)
2006	-	2,744	12,771	125,458	113,443	(12,015)	(15,142)
Total	$ 17,051	$ 4,280					

Effective composite income tax rate 38.91%

SETTLEMENT

Hawaii Electric Light Company
Financial Ratios

Test Year 2006	NO Rate Increase per RWP-1806, p.1-5	WITH Rate Increase per RWP-1806, p.6-10
Funds from Operations Interest Coverage *	3.49 x	4.45 x
Funds from Operations / Average Total Debt *	16%	22%
Total Debt / Total Capital *	55%	55%
Total Debt / Total Capital without Debt Equivalent	50%	50%

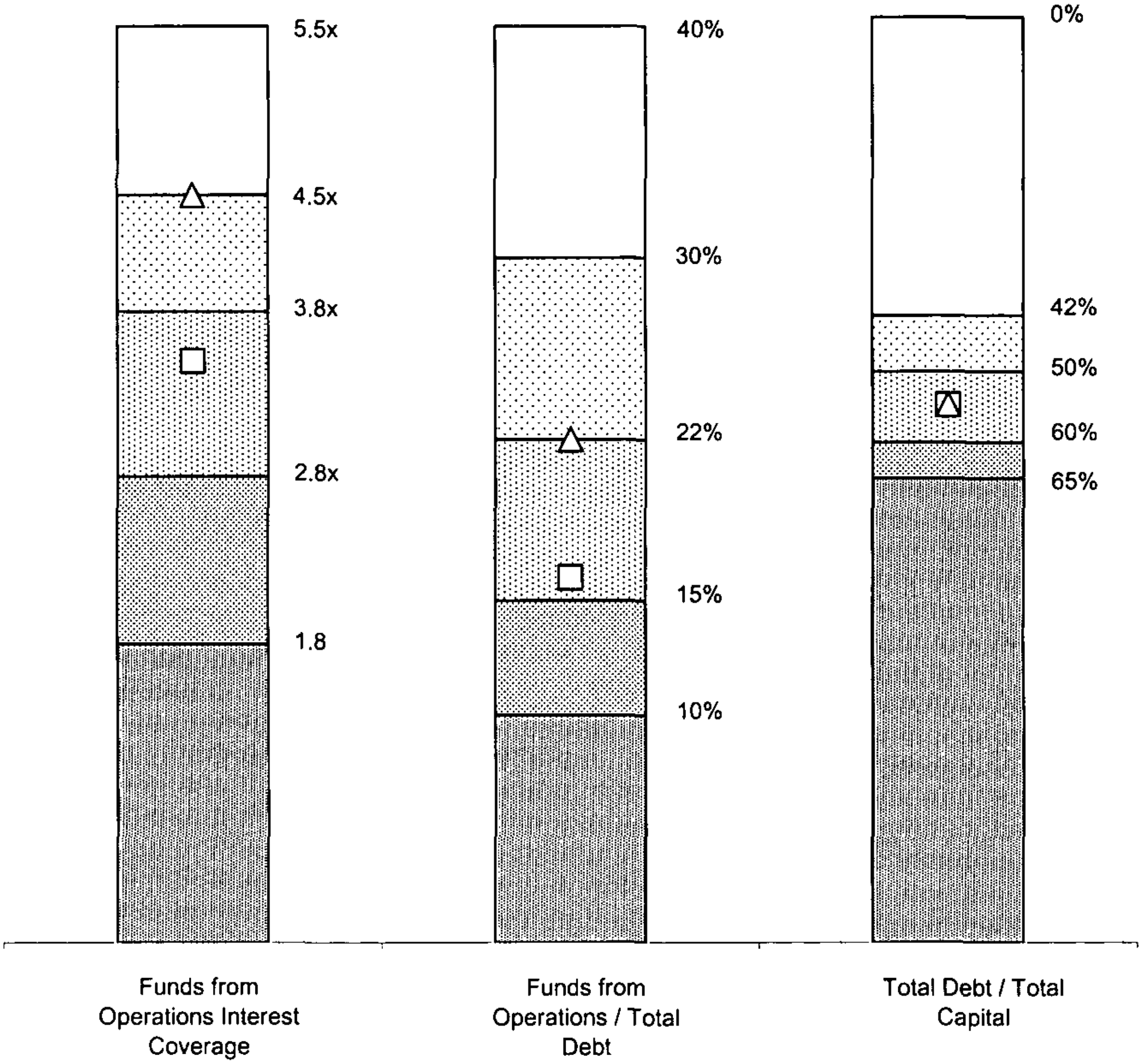
2005 Actual	
Total Debt / Total Capital *	53%
Total Debt / Total Capital without Debt Equivalent	48%

* These ratios take into account the debt equivalent (off-balance sheet purchased power obligations).

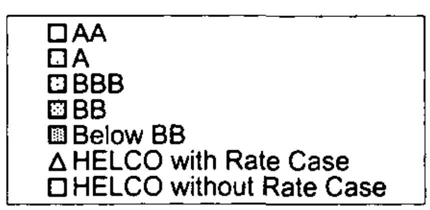
SETTLEMENT

Financial Ratios in Comparison to S&P Rating Guidelines

Business Profile = 5



	Funds from Operations Interest Coverage	Funds from Operations / Total Debt	Total Debt / Total Capital
HELCO w/ Rate Case	4.5 x	22%	55%
HELCO w/out Rate Case	3.5 x	16%	55%



Hawaii Electric Light Company
Financial Ratios

Test Year 2006	NO Rate Increase per RWP-1806, p.11-15	WITH Rate Increase per RWP-1806, p.16-20
Funds from Operations Interest Coverage *	3.49 x	4.64 x
Funds from Operations / Average Total Debt *	16%	23%
Total Debt / Total Capital *	55%	55%
Total Debt / Total Capital without Debt Equivalent	50%	50%

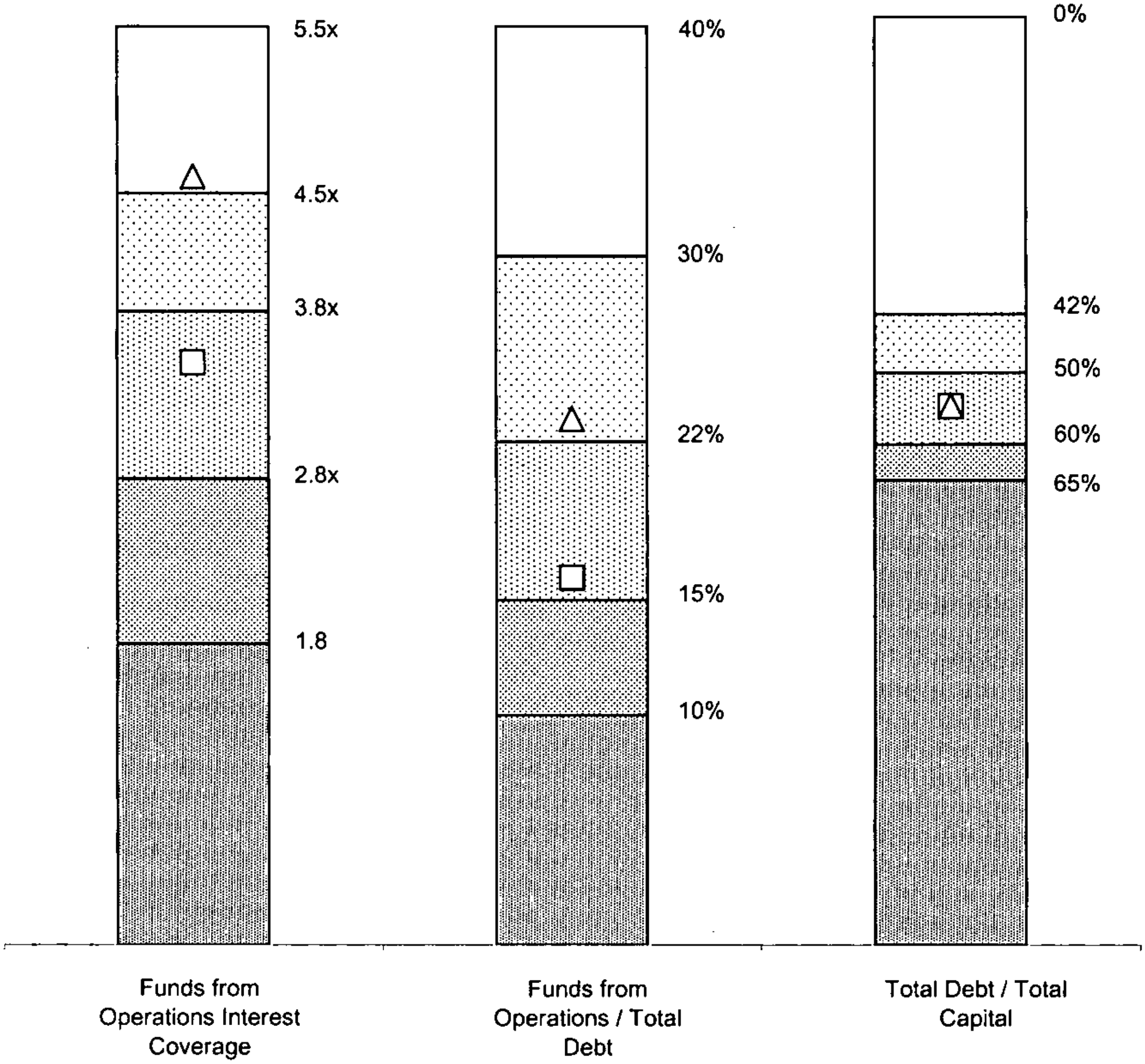
2005 Actual

Total Debt / Total Capital *	53%
Total Debt / Total Capital without Debt Equivalent	48%

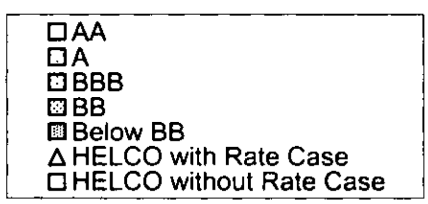
* These ratios take into account the debt equivalent (off-balance sheet purchased power obligations).

Financial Ratios in Comparison to S&P Rating Guidelines

Business Profile = 5



	Funds from Operations Interest Coverage	Funds from Operations / Total Debt	Total Debt / Total Capital
HELCO w/ Rate Case	4.6 x	23%	55%
HELCO w/out Rate Case	3.5 x	16%	55%



Hawaii Electric Light Co., Inc.
Rate of Return on Rate Base and On Common Equity - Ratemaking
For the 12 Months Ended December 31

	Simple Average		Weighted Average	
Year	Rate of Return On RATE BASE	Rate of Return On COMMON EQUITY	Rate of Return On RATE BASE	Rate of Return On COMMON EQUITY
2000	9.36%	9.24%	9.41%	9.14%
2001	8.97%	7.89%	9.13%	7.80%
2002	9.15%	7.52%	9.20%	7.44%
2003	8.65%	6.61%	8.80%	6.53%
2004	7.25%	6.98%	7.39%	6.97%
2005	6.08%	6.86%	6.22%	6.81%
2006	4.50%	3.70% *	4.59%	3.69% *

* For the 2006 return on common equity calculation, the common equity amounts reflect an adjustment to HELCO's book equity, to exclude the amounts that were charged to Accumulated Other Comprehensive Income (AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158, on December 31, 2006.

NOTE: The above ratemaking returns have been filed with the Commission.

CONSUMER ADVOCATE
PROPOSED PENSION TRACKING MECHANISM

Purpose: The proposed pension tracking mechanism is designed to achieve the following objectives:

A. Ensure that the pension costs recovered through rates are based on the FAS87 NPPC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the pension trust funds (subject to the exceptions in Item 3 below) are in an amount equal to actual NPPC and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS87, FAS158 or any other FASB statement or procedure relative to the recognition of pension costs and/or liabilities.

Procedure:

1. The amount of FAS87 NPPC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Except when limited by the ERISA minimum contributions requirements or the maximum contribution imposed by the IRC, or the contribution exceeds the NPPC for a reason provided in Item 3, the annual contribution to the pension trust fund will be equal to the amount of FAS87 NPPC.

3. The utility will be allowed to recover through rates the amount of any contributions to the pension trust in excess of the FAS87 NPPC that were made for the following reasons[1]:

[1] The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

- the minimum required contribution is greater than the FAS 87 NPPC,

- the increased contribution was made to avoid a significant increase in Pension Benefit Guaranty Corporation (PBGC) variable premiums,

- the increased contribution was made to avoid a charge to other comprehensive income, or

- the increased contribution was made to avoid: (i) higher minimum contribution requirements under the Pension Protection Act,[2] or (ii) other adverse funding requirements under federal pension regulations (provided funding does not exceed 100% of the PBO as a result). The recoverability of any discretionary contributions (as described under this bullet item) shall be subject to review in the Company's next rate case.

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS87 NPPC during the rate effective period and the level of FAS87 NPPC included in rates during that same period.

    - The unamortized cumulative net ratepayer benefit of approximately $12.8 million, as of December 2006, shall be included in rate base and amortized over a five year period.

    - if the actual FAS 87-determined NPPC recorded during a given rate-effective period is greater than the FAS87 NPPC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is <u>not</u> used to reduce a regulatory liability recorded pursuant to Item 5.

    - If the actual FAS87-determined NPPC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a

[2] Transitional relief applies under the Pension Protection Act if the plan's target liability funded level meets the prescribed phase-in percentages for 2008 through 2011. The Parties recognize that such transitional relief or related requirements may be subject to change or revision in future years.

regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

- If the actual FAS 87 NPPC becomes negative, the regulatory liability will be increased by the difference between the level of FAS87 NPPC included in rates for that period and "zero" (i.e., $0).
- Since this is considered to be a cash item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

5. If the FAS87 NPPC becomes negative, the Company will set up a regulatory liability to offset the prepaid pension asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPPC, or decrease by the amount of positive NPPC, in each subsequent year. Positive NPPC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

    - If NPPC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).
    - if NPPC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).
    - Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS87-based NPPC, including the amortization of unrecognized amounts as set forth above.

    - The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., decreases to other comprehensive income) caused by applying the provisions of FAS87, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's pension plan.

- This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS87 NPPC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS87 and, pursuant to other provisions of this proposal, all FAS87-determined NPPC will over time ultimately be recovered from ratepayers.

- The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless of whether the term is longer or shorter than five years.

    - If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case over a five year period and any unamortized balance shall be included in rate base.

    - If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any prepaid pension asset or accrued liability recorded pursuant to the terms and conditions of FAS87 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will <u>not</u> be included in Rate Base in any future rate case, except for the unamortized portion of the $12.8 million of cumulative net ratepayer benefits previously identified. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for pension differences.

**Comments & Clarifications
Regarding the Consumer Advocate's
Proposed Pension Tracking Mechanism**

1. The proposed tracking mechanism refers to "NPPC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS87 net periodic costs.

2. "NPPC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by IRC maximum contributions or ERISA minimum contributions, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 net periodic costs determined for each calendar year.

4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS87 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS87 may require a company to record a prepaid pension asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

    a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future prepaid pension asset resulting from an actuarial study that resulted in "negative" net periodic costs.

    b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS87 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to

funding 100% of the FAS87 net periodic costs for both HELCO and the affiliate **or** to maintain segregated pension trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise In the future.

7. Any commitment by HELCO to fund 100% of its FAS87 net periodic costs (as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each HELCO affiliate. However, in future rate proceedings, the Consumer Advocate will propose that a substantially similar pension tracking mechanism be implemented by HELCO's affiliates.

8. When an order is issued by the Commission which: 1) adopts the tracking mechanism and 2) establishes new rates that explicitly incorporate the provisions of the mechanism in the new rates, HELCO will fund the NPPC for the calendar year of the date of the order based on a monthly proration of the annual NPPC.

PROPOSED OPEB TRACKING MECHANISM

Purpose: The proposed OPEB tracking mechanism is designed to achieve the following objectives:

A. Ensure that the OPEB costs recovered through rates are based on the FAS106 NPBC, as reported for financial reporting purposes;

B. Ensure that all amounts contributed to the OPEB trust funds (subject to the exception in Item 3 below) are in an amount equal to actual NPBC and are recoverable through rates; and

C. Clarify the future treatment of any charges that would otherwise be recorded to equity (e.g., increases/decreases to other comprehensive income) as required by FAS106, FAS 158 or any other FASB statement or procedure relative to the recognition of OPEB costs and/or liabilities.

Procedure:

1. The amount of FAS 106 NPBC included in rates shall be equal to the amount recognized for financial reporting purposes.

2. Except when limited by material, adverse consequences imposed by federal regulations, the annual contribution to the OPEB trust funds will be equal to the amount of FAS106 NPBC. The utility will use tax advantaged funding vehicles, whenever possible, as specified in D&O 13659, dated November 29, 1994, in Dockets 7243 and 7233 (Consolidated).

3. The utility will be allowed to recover through rates the amount of any contributions to the OPEB trusts in excess of the FAS106 NPBC that were made for the following reason[1]:

[1] The Company or the Consumer Advocate (jointly, the "Parties") may initiate discussions with the Parties and the Hawaii Public Utilities Commission to modify these provisions between rate cases (with Commission approval) if there are future changes in accounting standards, federal tax law or federal tax regulations that materially impact the costs otherwise recoverable through this tracking mechanism.

- the increased contribution was made to avoid a charge to other comprehensive income.

Any such "excess" contributions shall be recorded in a separate regulatory asset account, which will be included in rate base.

4. A regulatory asset (or liability) will be established on the Company's books to track the difference between the level of actual FAS106 NPBC during the rate effective period and the level of FAS106 NPBC included in rates during that same period.

    - If the actual FAS 106-determined NPBC recorded during a given rate-effective period is greater than the FAS106 NPBC included in rates during the immediately preceding rate case, the Company will establish a separate regulatory asset account to accumulate such difference, but only to the extent that such amount is not used to reduce a regulatory liability recorded pursuant to Item 5.

    - If the actual FAS106-determined NPBC recorded during the rate-effective period, adjusted for any amount of such expense used to reduce a regulatory liability maintained pursuant to Item 5, is less than the expense built into rates, the Company will establish a separate regulatory liability account to accumulate such difference.

    - If the actual FAS 106 NPBC becomes negative, the regulatory liability will be increased by the difference between the level of FAS106 NPBC included in rates for that period and "zero" (i.e., $0).

    - Since this is considered to be a cash item under the tracking mechanism, the regulatory asset or liability will be included in rate base and amortized over a five (5) year period at the time of the next following rate case.

5. If the FAS106 NPBC becomes negative, the Company will set up a regulatory liability to offset the OPEB asset created by the negative amount. This regulatory liability will increase by the amount of any negative NPBC, or decrease by the amount of positive NPBC, in each subsequent year. Positive NPBC in each subsequent year will be used to reduce the regulatory liability before being used to establish a regulatory asset pursuant to Item 4.

    - If NPBC is negative at the time of the next rate case, the amount included in rates will be "zero" (i.e., $0).

- If NPBC is positive at the time of the next rate case, the positive expense will not be included in rates and the Company will not be required to make contributions to the trust until any regulatory liability created under this Item 5 has been reduced to "zero" (i.e., $0).

- Since this regulatory liability is considered to be a non-cash item under the tracking mechanism, it is not subjected to amortization and should not be recognized in determining rate base in future years.

6. The objective of this tracking mechanism is that, over time, the Company will recover through rates FAS106-based NPBC, including the amortization of unrecognized amounts as set forth above.

    - The Company will establish a separate regulatory asset/liability account to offset any charge, or credit, that would otherwise be recorded against equity (e.g., increases/decreases to other comprehensive income) caused by applying the provisions of FAS106, FAS158 or any other FASB statement or procedure that requires accounting adjustments due to the funded status or other attributes of the Company's OPEB plans.

    - This regulatory asset/liability will not be amortized into rates or included in rate base, because any such charges are expected to be recovered in rates through the valuation of FAS106 NPBC in future accounting periods, which will be subject to the true-up process described herein. In other words, this regulatory asset/liability will automatically be reversed through the mechanics of FAS106 and, pursuant to other provisions of this proposal, all FAS106-determined NPBC will over time ultimately be recovered from ratepayers.

    - The regulatory asset/liability will increase or decrease each year by the same amount that the equity charge increases or decreases.

7. Recognizing that rate cases do not typically occur on a five-year cycle, the Company will continue to record any amortizations allowed herein throughout the effective term that the approved rates remain in effect, regardless whether the term is longer or shorter than five years.

- If the rate effective period is less than five years, the Company will be allowed to recover any unamortized and unrecovered amounts in the next following rate case over a five year period and any unamortized balance shall be included in rate base.

- If the rate effective period is greater than five years, the Company will be required to establish a separate regulatory asset or liability to accumulate any excess amortization, which shall be included in rate base and amortized over a five year period in the next following rate case.

8. Any OPEB asset or accrued liability recorded pursuant to the terms and conditions of FAS106 (as opposed to regulatory assets arising from the provisions of this proposed tracking mechanism) will not be included in Rate Base in any future rate case. The regulatory assets/liabilities discussed herein specifically identify all rate base includable amounts for OPEB differences.

Comments & Clarifications
Regarding the Proposed OPEB Tracking Mechanism

1. The proposed tracking mechanism refers to "NPBC" in explaining how the mechanism operates, which is intended to represent actuarially determined total FAS106 net periodic costs.

2. "NPBC" intentionally encompasses total actuarially determined amounts without regard to any expense allocation or capitalization accounting the Company may recognize on its books and records.

3. Unless limited by adverse consequences under federal regulations, the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS106 net periodic costs determined for each calendar year.

4. The proposed tracking mechanism requires the Company to establish a regulatory asset or liability for the difference between the total FAS106 net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.

5. The provisions of FAS106 may require a company to record an OPEB asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:

    a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any future OPEB asset resulting from an actuarial study that resulted in "negative" net periodic costs.

    b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to "zero" (i.e., $0).

6. If the utility is allocated a portion of the FAS106 net periodic costs from an affiliated entity in the normal course of business and the tracking mechanism is approved by the Commission, the Company would be required to commit to funding 100% of the FAS106 net periodic costs for both HELCO and the

affiliate **or** to maintain segregated OPEB trust fund accounting for each entity in order to avoid any funding conflicts or issues that might arise In the future.

7. Any commitment by HELCO to fund 100% of its FAS106 net periodic costs (as limited under item 3) will not be contingent on implementing a substantially similar tracking mechanism for each HELCO affiliate. However, in future rate proceedings, a substantially similar OPEB tracking mechanism will be proposed for HELCO's affiliates.

Witness HELCO T-19

has no rebuttal testimony.

Witness HELCO T-19

has no rebuttal exhibits.

REBUTTAL TESTIMONY OF PETER C. YOUNG

DIRECTOR, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Cost of Service and Rate Design

INTRODUCTION

Q. Please state your name and business address.

A. My name is Peter C. Young, and my business address is 200 South King Street, Suite 1201, Honolulu, Hawaii, 96813.

Q. By whom are you employed and in what capacity?

A. I am employed by the Hawaiian Electric Company, Inc. as the Director of the Pricing Division. My experience and educational background are listed in HELCO-300.

Q. Have you testified before the Commission in prior Company proceedings?

A. Yes. I have appeared as the Company's witness on test year revenues, cost of service, and rate design in prior HELCO, HECO, and MECO rate case proceedings, as listed in HELCO-300.

Q. What will you cover in HELCO RT-20?

A. My testimony in HELCO RT-20 will cover the following:

1) HELCO's revised cost-of-service study for rebuttal testimony;
2) The allocation of the proposed revenue increase;
3) HELCO's proposed rate design and rates; and
4) HELCO's rebuttal response to the testimonies of the Consumer Advocate on cost-of-service, allocation of revenue increase, and rate design.

Due to the lead time required to prepare the cost of service study and rate design, the filed testimony, exhibits, and workpapers do not reflect the agreements reached with the Consumer Advocate. Instead, the cost of service study and rate design exhibits and workpapers are based on a pre-settlement revenue requirements analysis that took into account some of the agreements reached with the Consumer Advocate, but not all of the agreements as, due to timing considerations, the analysis was completed before all of the agreements were finalized with the Consumer Advocate. The pre-settlement revenue requirements analysis is further discussed by Mr. Warren Lee in HELCO RT-21. Subsequent to the filing of the rebuttal testimony, the Company will submit revised cost of service and rate design exhibits and workpapers that reflect the agreements reached with the Consumer Advocate. In addition, as discussed below, the Company and the Consumer Advocate plan to have further discussions to address the remaining cost of service, revenue allocation and rate design issues.

Q. Will you discuss HELCO's proposed Schedule R rate design and its associated issues?

A. Yes. I will discuss the issues related to HELCO's proposed Schedule R rate design in rebuttal testimony, and Dr. Orans will not be providing rebuttal testimony to his HELCO T-19 direct testimony on HELCO residential rate structure.

REBUTTAL COST OF SERVICE STUDY

Q. What are the results of the rebuttal cost of service study (based on the pre-settlement revenue requirements analysis)?

A. The results of the cost of service study are summarized in the following exhibits:

1) HELCO-R-2001 shows the classes' revenues and rates of return at present rates and at proposed rates;
2) HELCO-R-2002 provides the determination of the classes' rates of return at present rates;
3) HELCO-R-2003 shows the determination of the classes' rates of return at

proposed rates;

4) HELCO-R-2004 is a summary of proposed allocation of rate increase by rate class;

5) HELCO-R-2005 is a summary of the allocation of rate increase by rate class required for equal rates of return;

6) HELCO-R-2006 is a comparison of revenue allocation and rates of return at present rates, proposed rates, and equal rates of return;

7) HELCO-R-2007 is a summary of the classes' classification of functionalized sales revenue requirements at proposed rates;

8) HELCO-R-2008 is a summary of the classes' unit functionalized sales revenue requirements at proposed rates;

9) HELCO-R-2009 is a summary of the classes' classification of functionalized sales revenue requirements at equal rates of return;

10) HELCO-R-2010 is a summary of the classes' unit functionalized sales revenue requirements at equal rates of return;

11) HELCO-R-2011 is a summary of demand, energy, and customer cost allocation factors; and

12) HELCO-R-2012 compares rate class revenue requirements and class rates of return between the rebuttal cost-of-service study and the study results presented in direct testimony.

Q. How do the results of the embedded cost-of-service study for this rebuttal testimony compare with those presented in HELCO's direct testimony?

A. HELCO's rebuttal total revenues at present rates are slightly lower than the total in direct testimony, as shown in HELCO-R-2012, page 1, primarily due to a small downward revision in the fuel oil adjustment factor. HELCO's rebuttal total revenues at proposed rates are lower than the total in direct testimony, as shown in HELCO-R-2012, page 2, due to lower estimates of operating expenses, and a slightly lower rate base and rate of return on rate base. The relative magnitude of the class rates of return at present rates from the rebuttal cost-of-service study are generally similar to the class rates of return at present rates shown in direct testimony. In both HELCO's rebuttal testimony and HELCO's direct testimony, the Schedule R and Schedule F class rates of return at present rates are below the system average rate of return, while Schedule G has the highest rate of return. All other commercial rate classes (G, J, H, and P) have rates of return that exceed the system average. In both HELCO's rebuttal testimony and HELCO's direct testimony, at proposed rates, the same pattern of rates of return emerges, although generally all rate class rates of return move towards the system average.

Q. Are there any changes to HELCO's embedded cost-of-service methodology?

A. No, the embedded cost-of service methodology remains the same as employed in direct testimony. HELCO did make changes to the cost-of-service assumptions that were identified in HELCO's responses to CA-IR-447 and CA-IR-448.

Q. What were the changes that HELCO identified in response to CA-IR-447?

A. In the response to CA-IR-447, HELCO identified revisions to the C7 and C8 allocation factors, a revision to the assumed kW per Schedule G customer, a revision to the Schedule G class load factor %, and a revision to the Schedule G load factor kWh per kW-measured. These revisions are incorporated into the rebuttal cost-of-service study, as shown in HELCO-RWP-2001.

Q. What were the changes that HELCO identified in response to CA-IR-448?

A. In the response to CA-IR-448, HELCO identified data errors and omissions in the development of its minimum system study for overhead secondary conductors, underground primary conductors, and underground secondary conductors. These errors and omissions are corrected and incorporated into the rebuttal cost-of-service study, as shown in HELCO-RWP-2001.

Q. What are the bases for the revisions to the embedded cost-of-service study in rebuttal testimony?

A. The updated embedded cost-of-service study for rebuttal testimony reflects the following:

1. Revised test year revenues at present rates presented in HELCO RT-3;
2. Revised pre-settlement test year estimates of O&M expenses, taxes, and rate base presented by the different Company witnesses; and
3. Revised test year total revenue requirements, based on the "pre-settlement" revenue requirements. Due to the lead time required to prepare the cost of service and rate design, the exhibits and workpapers filed with this testimony do not reflect the agreements reached with the Consumer Advocate. Subsequent to this filing, the Company will submit revised cost of service and rate design exhibits and workpapers to reflect the agreements reached between the Company and the Consumer Advocate.

MARGINAL COST STUDY

Q. Are there any changes to HECO's marginal cost study?

A. No. The marginal cost study was not revised from what was presented in direct testimony.

ALLOCATION OF PROPOSED REVENUE INCREASE

Q. What is HELCO's proposed allocation of revenue increase (based on the pre-settlement revenue requirements analysis)?

A. HELCO's proposed allocation of revenue increase is presented in HELCO-R-2004.

Q. Please describe how the proposed allocation of revenue increase among the rate classes was determined.

A. The proposed allocation of the revenue increase among the rate classes is summarized in HELCO-R-2004. The proposed allocation follows the guidelines applied in previous dockets, to allocate the proposed revenue increase to rate classes such that each class would move closer to cost of service, as reflected by each class's rate of return moving closer to the system average rate of return. In implementing the guidelines, HELCO proposes the same approach that was taken in direct testimony. HELCO proposes to increase Schedule R, Schedule G, and Schedule H class revenues by 8.32%, which is 100% of the system average increase of 8.32%. HELCO proposes to increase Schedule F class revenues by 10.39%, which is 125% of the system average increase. HELCO proposes to limit the Schedule P class revenue increase to 6.24%, which is 75% of the system average increase. The Schedule J assigned class revenue increase is 9.56% to balance the total request. This proposal moves the rate of return for all classes except Schedule J closer to the system average rate of return at proposed rates as shown in the rate of return index in HELCO-R-2001. All classes meet the rate of return guideline of ± 50% of the system average at the proposed revenue allocation.

Q. Please discuss the proposed allocation of revenue increase compared with the proposal offered by the Consumer Advocate.

A. In HELCO's proposed revenue allocation, the percentage allocation of the total revenue increase assigned to each class shown in the last column of HELCO-R-2004 is very similar to what the Consumer Advocate proposes at CA-T-5, page 43. The only meaningful differences are in Schedule R and Schedule G: for Schedule R, the HELCO proposal assigns 40.1% of the total revenue increase to Schedule R, while the Consumer Advocate proposal assigns 43.8%; and for Schedule G, the HELCO proposal assigns 10.5% of the total revenue increase to Schedule G, while the Consumer Advocate proposal assigns only 7.0%.

Q. Please discuss the required class revenue requirements at equal rates of return presented in HELCO-R-2005.

A. The classes' revenue requirements that result in the class rates of return equal to the system rate of return are generally referred to as the classes' full cost of service. The proposed total revenue requirements of $351,125,000 results in the proposed system rate of return on rate base of 8.61%. HELCO-R-2005 provides a summary of the classes' revenue requirements and rate increase that would result with each class providing the same 8.61% rate of return on rate base. For instance, Schedule R's revenue requirement at 8.61% rate of return is $149,305,300, which requires a 15.24% rate increase for Schedule R. On the other hand, Schedule G's revenue requirement at 8.61% rate of return is $33,744,200, which results in a 0.47% rate <u>decrease</u> for Schedule G. A summary comparison of the classes' revenue requirements and rates of return at present rates, at proposed rates, and at the classes' full cost of service is provided in HELCO-R-2006.

RATE DESIGN AND PROPOSED RATES

Q. Why are changes made to HELCO's proposed rates in rebuttal testimony?

A. HELCO's revisions to proposed rates reflect the changes in revenue requirements (pre-settlement) made in the Company's rebuttal testimony.

Q. *Are there changes proposed for HELCO's structure of rates and rules in rebuttal?*

A. The proposed changes to the structure of HELCO's rates and rules, including the proposed changes to terms and conditions in rates and riders, remain the same as proposed in direct testimony. In addition, HELCO agrees with the Consumer Advocate's proposed increase to service charges in HELCO's Rule No. 7 and Rule No. 8, which will be discussed below.

Q. How does HELCO propose to reflect the changes to the proposed class revenue requirements in rebuttal testimony?

A. HELCO proposes to reflect the rebuttal changes in class revenue requirements in the proposed rate class and rate rider energy charges to the extent possible. Summaries of the allocation of proposed revenue requirements among rate elements by rate class are presented in HECO-R-2013. The revised proposed rate and rule sheets are presented in HELCO-R-2015. Sample bill comparisons under present and proposed rates by rate schedule are presented in HELCO-R-2016.

Q. What are the revisions to HELCO's proposed rates?

A. The proposed rate design changes (pre-settlement) to each rate schedule are summarized in the following section:

1) Schedule R – Residential Service

A. Increase the Base Fuel Energy Charge from 7.6132 ¢/kWh to 16.7455 ¢/kWh; and

B. Change the Non-Fuel Energy Charge from 11.5238 ¢/kWh to three tiers, 12.5244 ¢/kWh for the first 300 kWh, 14.6349 ¢/kWh for the next 700 kWh, and 15.4656 ¢kWh for all kWh over 1000 kWh per billing period. The changes to the minimum charge and the energy charge limit for customers under the Low Income Home Energy Assistance Program (LIHEAP) remain as proposed in direct testimony. There are no changes proposed to Schedule E in rebuttal. The proposed Base Fuel Energy Charge is based on the Company's rebuttal estimates cost of fuel and cost of purchased power, as shown in HELCO-R-2014. The proposed Non-Fuel Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and minimum charges.

The proposed changes to Schedule R are designed to produce the proposed allocated class revenue requirements of $140,331,100 as shown in HELCO-R-2013.

2) Schedule G – General Service Non-Demand

Increase the Energy Charge from 21.3604 ¢/kWh to 32.2535 ¢/kWh. The changes to the availability clause, customer charges and primary voltage service remain as proposed in direct testimony. The proposed Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and minimum charges. The proposed changes to Schedule G are designed to produce the proposed allocated class revenue requirements of $36,723,900 as shown in HELCO-R-2013.

3) Schedule J – General Service Demand

Increase the Energy Charge for the three load factor blocks from 16.4579 ¢/kWh, 14.2407 ¢/kWh, and 13.2397 ¢/kWh to 26.1538 ¢/kWh, 23.9367

¢/kWh, and 22.9357 ¢/kWh, respectively.

The changes proposed to the availability clause, the customer charges, the demand charge, the demand ratchet, and the Primary Supply Voltage Service provision remain as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer, demand, and minimum charges, net of power factor, primary supply voltage service, and rider adjustments.

The proposed changes to Schedule J rates are designed to produce the proposed allocated class' revenue requirements of $104,623,300 as shown in HELCO-R-2013.

4) Schedule H – Commercial Cooking and Heating Service

Increase the Energy Charge from 15.9189 ¢/kWh to 26.4183 ¢/kWh.

The proposed changes to the customer charges and demand charge remain the same as in direct testimony. The proposed Energy Charge recovers the customer costs and demand costs that are not recovered by the customer and demand charges. The proposed changes to Schedule H are designed to produce the class's total allocated revenue requirements of $5,204,500 as shown in HELCO-R-2013.

5) Schedule P – Large Power Service

Increase the Energy Charge for the three load factor blocks from 15.2290 ¢/kWh, 13.0488 ¢/kWh, and 12.0458 ¢/kWh, to 24.0599 ¢/kWh, 21.8797 ¢/kWh, and 20.8767 ¢/kWh, respectively.

The proposed changes to the availability clause, the customer charge, the demand charges, and the supply voltage delivery provision remain the same as proposed in direct testimony. The proposed Energy Charges recover the customer costs and demand costs that are not recovered by the customer and demand charges, net of the power factor, supply voltage discounts, and rider adjustments. The proposed changes to Schedule P rates are designed to produce the proposed allocated class' revenue requirements of $61,761,800 as shown in HELCO-R-2013.

6) Schedule F – Street Light Service

Increase the energy charge for the two load factor blocks from the present 22.7311 ¢/kWh and 16.5301 ¢/kWh to 34.6893 ¢/kWh and 28.4883 ¢/kWh, respectively.

The proposed changes to Schedule F rates are designed to produce the proposed allocated class' revenue requirements of $1,379,600, as shown in HELCO-R-2013.

7) Schedule U – Time-of-Use Service

Increase the Energy Charge from the current 16.4579 ¢/kWh for on-peak period to 26.1538 ¢/kWh, and from 12.0458 ¢/kWh for off-peak period to 21.1260 ¢/kWh.

The changes to the customer charge, demand charge, and the supply voltage delivery provision remain as proposed in direct testimony.

8) Schedule Q – Purchases from Qualifying Facilities 100 kW or Less

A. Change the Energy Rates for energy delivered to the Company by the customer from the current 7.12 ¢/kWh to 15.83 ¢/kWh; and

B. Change the generation base fuel cost from the current 469.72 ¢/mbtu to 1,064.54 ¢/mbtu, as shown in HELCO-RWP-2204.

The test-year fuel price and efficiency factors used to determine this composite generation cost are discussed in HELCO RT-22.

9) Energy Cost Adjustment Clause

A. Change the base fuel cost for Company composite cost of generation from central station, wind, and hydro sources from current 469.72 ¢/mbtu to 1,064.43 ¢/mbtu;

B. Change the Company generation efficiency factor from the current 0.014629 mbtu/kWh to use three separate efficiency factors, 0.015615 mbtu/kWh for industrial fuel, 0.013526 mbtu/kWh for diesel fuel, and 0.014826 mbtu/kWh for other company generation sources;

C. Add a DG (Distributed Generation) Energy Component in the Clause at 14.942 cents per kWh, adjusted to the sales delivery level and for revenue taxes; and

D. Change the base purchased energy cost from the current 6.404 ¢/kWh to 13.631 ¢/kWh.

The proposed changes to the base fuel costs, generation efficiency factors, and DG Energy Component are discussed in HELCO RT-22.

10) Schedule TOU-R – Residential Time-of-Use Service

There are no changes to the proposal made in direct testimony.

11) Schedule TOU-G – Small Commercial Time-of-Use Service

A. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	37.2535 ¢ per kWh,
Mid-Peak Period kWh use	34.7535 ¢ per kWh, and
Off-Peak Period kWh use	27.2535 ¢ per kWh;

The customer charges, minimum bill, time-of-use rating periods, and meter limit remain as proposed in direct testimony.

12) Schedule TOU-J – Commercial Time-of-Use Service

A. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	32.2063 ¢ per kWh,
Mid-Peak Period kWh use	30.2063 ¢ per kWh, and
Off-Peak Period kWh use	20.2063 ¢ per kWh;

The customer charges, demand charges, minimum charge, time-of-use rating periods, and meter limit remain as proposed in direct testimony.

13) Schedule TOU-P – Large Power Time-of-Use Service

A. Energy Charges: Apply to all kWh

Priority Peak Period kWh use	29.5793 ¢ per kWh,
Mid-Peak Period kWh use	27.5793 ¢ per kWh, and
Off-Peak Period kWh use	17.5793 ¢ per kWh;

The customer charge, demand charges, minimum charge, time-of-use rating periods, and meter limit remain as proposed in direct testimony.

COST-OF-SERVICE ISSUES

Q. What are the cost-of-service issue differences raised by the Consumer Advocate?

A. In CA-T-5, the Consumer Advocate raises the following issues with which the Company does not agree:

1. Distribution poles, lines, and transformers are improperly classified as "customer" costs; and
2. Production O&M expenses other than fuel are classified entirely as fixed or "demand" costs, when a portion of such expenses vary with the level of generation.

Q. Have the Company and the Consumer Advocate come to an agreement regarding the cost of service issues in settlement discussions?

A. Yes. The Company and the Consumer Advocate agree that the revenue allocation and rate design issues can be resolved without the need to address the cost of service issues at this time.

Q. What are the Consumer Advocate's contentions about the classification of distribution poles, lines and transformers?

A. The Consumer Advocate says that the distribution network of poles, lines, and transformers do not vary directly with the number of customers served and should be classified entirely as demand costs, rather than partially as customer costs, as HELCO proposes (CA-T-5, page 12). The Consumer Advocate also contends that HELCO's use of the minimum system method is flawed because it double counts cost responsibility. The Consumer Advocate argues that the minimum-sized distribution system is capable of serving a large percentage of customer demand, but no credit is given for this demand serving capability when allocation factors are devised and applied to the "demand" component of distribution network costs (CA-T-5, page 25).

Q. Has the Commission approved the Company's cost-of-service methodology in prior rate cases?

A. The Commission has found reasonable the Company's classification of distribution plant costs as demand-related and customer-related and the Company's use of the minimum system method as consistent with NARUC cost allocation guidelines in previous rate cases (Decision and Order No. 11699 in HECO's Docket No. 6998, Decision and Order No. 18365 in HELCO's Docket No. 99-0207, and Amended Decision and Order No. 16922 in MECO's Docket No. 97-0346) and has not agreed with the Consumer Advocate's position.

Q. Are the Consumer Advocate's arguments different from what has been argued in the past?

A. No. The Consumer Advocate has not presented any new substantive arguments to support its proposal.

Q. What is the Company's position on the Consumer Advocate's contention concerning the alleged double-counting by the minimum system method?

A. The Company continues to disagree with the Consumer Advocate's contention:

1) The Minimum System Method is one of the methodologies specifically approved by the NARUC Cost Allocation Manual;

2) In Docket No. 6998, HECO argued that the distribution costs that are classified as demand-related only reflect the costs of the distribution plant required to meet the customers' expected kW demand. The distribution costs that are classified as demand-related are allocated to the customer only once, based on the composite class non-coincident peak demand. To the extent that an individual customer's expected kW demand is small or close to the minimum system load, such low demand is reflected a class composite non-coincident demand, and a class is accordingly allocated a smaller share of the distribution demand costs proportionate to the class' non-coincident peak demand. In the same manner, the distribution costs that are classified as customer-related only reflect the distribution plant costs required to connect the customer to the utility system whether or not the customer's kW demand is equal to or different from the minimum load size. The customer-related component is also allocated to the rate classes only once, proportionate to the number of customers by

rate class (Docket No. 6998, HECO RT-14, pages 38-39); and

3) In Docket No. 97-0346, MECO argued that the Consumer Advocate's proposal to adjust the demand included in the demand allocation factors (D2 and D3) understates the actual demand that is required of the distribution substations, distribution lines, and transformers, and results in inappropriate and inaccurate demand allocation factors (Docket No. 97-0346, MECO RT-17, page 27).

These arguments were accepted by the Commission in their decisions in these dockets.

Q. Does the Consumer Advocate recognize that the Company's classification method is reasonable?

A. Yes. The Consumer Advocate recognizes that HELCO's classification of distribution network costs, including poles, lines, and transformers, as customer-related is "consistent with alternatives documented within the NARUC Cost Allocation Manual . . ."(CA-T-5, page 14).

Q. What is HELCO's recommendation on this issue?

A. HELCO recommends that the Commission not accept the Consumer Advocate's arguments and continue to find HELCO's classification of distribution plant costs as demand-related and customer-related and the Company's use of the minimum system method, consistent with NARUC cost allocation guidelines, as reasonable.

Q. Does the Consumer Advocate propose a change in classification of production O&M expenses in the current HECO rate case?

A. Yes. The Consumer Advocate proposes that approximately 20% of non-fuel production O&M expenses should be classified as energy-related based on application of the FERC predominance method (CA-T-5, page 37).

Q. Is the Consumer Advocate's position reasonable?

A. No. Although the FERC predominance method may appear on the surface to be useful in classification of non-fuel production O&M costs, the Consumer Advocate appears to have assumed, that certain production O&M expenses are "predominantly variable" without undertaking an examination of the underlying composition of those expenses. It is not immediately clear to HELCO that this is an appropriate and reasonable treatment.

Q. What does HELCO recommend for the classification of production O&M expenses?

A. HELCO's classification of non-fuel production O&M costs as 100% demand-related is reasonable, has been approved in previous rate cases, and should be accepted by the Commission.

RATE DESIGN ISSUES

Q. Has the Company revised some of its positions on rate design based on settlement discussions with the Consumer Advocate?

A. Yes. The Company's revised positions will be discussed in the testimony below. Due to the lead time required to prepare the cost of service and rate design, the exhibits and workpapers filed with this testimony do not reflect the Company's stated positions in this testimony. Subsequent to this filing, the Company will submit revised cost of service and rate design exhibits and workpapers to reflect the settlement agreements reached between the Company and the Consumer Advocate. In addition, the Company and the Consumer Advocate plan to have further discussions to address the remaining cost of service, revenue allocation, and rate design issues discussed below.

Q. What are the rate design issue differences raised by the Consumer Advocate?

A. In CA-T-5, the Consumer Advocate and the Company's direct testimony differ on the following issues:

1. Usage in the first two energy blocks of Schedule R, up to 1000 kWh per month usage should receive the average percentage revenue increase ultimately ordered for the residential class;
2. The alternative proposed Schedule R minimum bill of 15% of the highest kWh usage in the last 11 months should not be approved;
3. Demand charge increases should be limited to 30%, and all other charges should be increased at an equal percentage change;
4. The Schedule P power factor adjustment should be changed to 0.10% from the existing 0.15%;
5. Rider A charges should be left in place at existing levels until Docket No. 2006-0497 is completed;
6. Miscellaneous service charges for service establishment, same day service, returned payment, and field collection should be revised and set at the levels agreed upon in settlement in HECO's Docket No. 04-0113; and
7. The proposed REEEPAH clause should not be approved.

Q. What is the Company's response to the Consumer Advocate's proposal to assign the average Schedule R class increase to the first two rate blocks of the proposed Schedule R inclining block design?

A. The Company believes its rate design rate proposals for the three proposed residential energy blocks create meaningful bill impact differences and should be approved. The merit of HELCO's proposed inclining rate block design include mitigation of the rate impact on the smallest users of the system, as shown in

Schedule R bill comparisons in HELCO-R-2016. That differentiation in bill impact is not achieved if the same percentage increase is applied to both the first and second tier blocks up to 1000 kWh per month as the Consumer Advocate suggests.

Q. What is the Company's response to the Consumer Advocate's proposal to reject the Company's proposed change to the Schedule R minimum bill provision?

A. The Company originally proposed a revision to the minimum bill to recover a greater contribution towards the fixed costs of serving residential customers through a steady monthly fee based on a fraction of the customer's maximum use of the electrical system. The Consumer Advocate does not agree with HELCO's proposal based on considerations of tariff complexity, ratepayer equity, and customer resistance. As agreed in settlement discussions with the Consumer Advocate, the Company will agree to the Consumer Advocate's proposal and withdraw the proposed modification to the Schedule R minimum bill in order to minimize the issues in this proceeding.

Q. What is the Company's response to the Consumer Advocate's proposal to limit demand charge increases to 30% and to increase all other charges at an equal percentage change?

A. HELCO's position is that the Company should not have arbitrary limits placed on its ability to align charges with costs. The Company's current customer charges and demand charges on the commercial rate schedules are below their cost level, as shown by the unit costs at proposed rates in HELCO-RWP-2001. This means that customer costs and demand costs are recovered in large measure through energy charges. Commercial customers who are high energy users in effect contribute a disproportionate share of fixed cost recovery. Principles of fairness and economic efficiency suggest that both customer charges and demand charges should be moved closer to their actual costs to serve. HELCO believes its rate design rate proposals are reasonable because the difference between demand charges and demand costs are significant, opportunities to adjust demand charges arise only in a rate case setting and within a rate case, total proposed demand costs may have increased further, meriting demand charge changes to reasonably maintain alignment with costs.

Q. What is the Company's response to the Consumer Advocate's proposal to reduce the Schedule P power factor adjustment to 0.10% from 0.15%?

A. The Company did not propose any changes to the power factor adjustment. The Consumer Advocate, in Mr. Herz's testimony at CA-T-2, proposes a 0.1% charge for customers with power factor less than 95% and no credits for customers with power factor above 95%. However, in CA-T-5, Mr. Brosch merely adjusts the Schedule P power factor adjustment rate from 0.15% to 0.1%, but effectively leaves in place the 85% power factor level with credits for power factor above 85% and charges for power factor below 85%. Further, Mr. Brosch also proposes that HELCO conduct a power factor study to be filed in HELCO's next rate case. As agreed in settlement discussions with the Consumer Advocate, the Company will accept a Schedule P power factor adjustment of 0.1% that leaves in place the 85% power factor level with credits for power factor above 85% and charges for power factor below 85% and agree to conduct a power factor study for the next HELCO general rate case.

Q. What is the Company's response to the Consumer Advocate's proposal to maintain Rider A charges at their existing levels?

A. The Company originally proposed to revise Rider A charges based on the proposed cost of service in this case. The Consumer Advocate proposed not to change Rider A charges since the issue of standby charges is addressed in Docket No. 2006-0497. As agreed in settlement discussions with the Consumer Advocate, the Company will accept the Consumer Advocate's proposal and will maintain Rider A charges at their existing levels.

Q. What is the Company's response to the Consumer Advocate's proposal to modify miscellaneous service charges for service establishment, same day service, returned payment, and field collection to the levels agreed upon in settlement in HECO's Docket No. 04-0113?

A. The Company accepts the Consumer Advocate's proposal and Mr. Fujioka has included the impact in his estimate of other operating revenues in HELCO RT-7. The accepted revisions to the miscellaneous service charges are reflected in the proposed modifications to Rule No. 7 and Rule No. 8 in HELCO-R-2015.

Q. What is the Company's response to the Consumer Advocate's proposal to not include the Company's proposed REEEPAH clause?

A. As agreed in settlement discussions with the Consumer Advocate, the Company will remove the REEEPAH dollars from the revenue requirement and withdraw the proposed REEEPAH clause. HELCO will include a proposal for renewable energy programs in its IRP-3, and will seek cost recovery through the IRP cost recovery provision. HELCO proposes to modify the current IRP cost recovery provision to include a "Renewable Energy Programs Adjustment", as shown in HELCO-R-2015. The Renewable Energy Programs Adjustment will recover the costs associated with renewable energy programs that are proposed within the HELCO IRP process and approved by the Commission.

SUMMARY

Q. Please summarize your testimony.

A. My testimony presented the Company's rebuttal embedded cost of service study, the basis and determination of the proposed rates, and the proposed changes to the Company's tariffs. The Company and the Consumer Advocate agree that the revenue allocation and rate design issues can be resolved without the need to address the cost of service issues at this time. The Company has modified its rate design for changes in the overall revenue requirement. As a result of settlement discussions with the Consumer Advocate, the Company agrees to withdraw the proposed revision to the Schedule R minimum bill, revise the power factor adjustment to 0.1% and undertake cost studies to support power factor tariff provisions in HELCO's next general rate case, maintain Rider A charges at their existing levels, revise the miscellaneous service charges to the levels proposed by the Consumer Advocate, withdraw the proposed REEEPAH clause, and propose a Renewable Energy Programs adjustment in the IRP cost recovery provision. The Company and the Consumer Advocate plan to have further discussions to address the remaining cost of service, revenue allocation, and rate design issues.

Q. Does this complete your testimony?

A. Yes.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF CLASS REVENUE REQUIREMENTS AND CLASS RATES OF RETURN
AT PRESENT RATES AND AT PROPOSED RATES

Rate Class	Present Rates: Sales Revenues ($000s)	Present Rates: Rate of Return (%)	Present Rates: ROR Index (%)	Proposed Rates: Sales Revenues ($000s)	Proposed Rates: Rate of Return (%)	Proposed Rates: ROR Index (%)	Proposed Increase: Amount ($000s)	Proposed Increase: Percent (%)
Schedule R	$129,555.8	2.22%	50%	$140,331.1	5.71%	66%	$10,775.3	8.32%
Schedule G	$33,904.1	8.80%	198%	$36,723.9	12.54%	146%	$2,819.8	8.32%
Schedule J	$95,497.8	5.52%	124%	$104,623.3	10.98%	128%	$9,125.5	9.56%
Schedule H	$4,804.9	5.51%	124%	$5,204.5	9.86%	115%	$399.6	8.32%
Schedule P	$58,135.4	6.53%	147%	$61,761.8	11.08%	129%	$3,626.4	6.24%
Schedule F	$1,249.7	2.81%	63%	$1,379.6	7.52%	87%	$129.9	10.39%
Total Sales Revenues	$323,147.7			$350,024.2			$26,876.5	8.32%
Other Operating Revenues	$925.4			$1,100.8			$175.4	18.95%
Total Revenues	$324,073.1	4.44%	100%	$351,125.0	8.61%	100%	$27,051.9	8.35%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PRESENT RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate Base ($000s)	Return on Rate Base (%)
Schedule R	$130,176.0	$126,216.8	$3,959.2	$178,297.0	2.22%
Schedule G	$33,978.9	$30,124.6	$3,854.3	$43,787.2	8.80%
Schedule J	$95,590.1	$90,263.0	$5,327.1	$96,439.1	5.52%
Schedule H	$4,816.6	$4,525.5	$291.1	$5,287.3	5.51%
Schedule P	$58,261.6	$55,249.3	$3,012.3	$46,121.4	6.53%
Schedule F	$1,249.9	$1,205.5	$44.4	$1,578.0	2.81%
TOTAL	$324,073.1	$307,584.7	$16,488.4	$371,510.0	4.44%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF CLASS RATES OF RETURN ON RATE BASE AT PROPOSED RATES

Rate Class	Total Operating Revenues ($000s)	Total Operating Expenses ($000s)	Total Operating Income ($000s)	Rate base ($000s)	Return on Rate Base (%)
Schedule R	$141,092.5	$130,998.8	$10,093.7	$176,910.7	5.71%
Schedule G	$36,814.3	$31,367.0	$5,447.3	$43,427.0	12.54%
Schedule J	$104,723.2	$94,265.5	$10,457.7	$95,278.8	10.98%
Schedule H	$5,217.1	$4,700.7	$516.4	$5,236.4	9.86%
Schedule P	$61,898.1	$56,839.7	$5,058.4	$45,658.8	11.08%
Schedule F	$1,379.8	$1,262.3	$117.5	$1,561.5	7.52%
TOTAL	$351,125.0	$319,434.0	$31,691.0	$368,073.2	8.61%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

PROPOSED ALLOCATION OF RATE INCREASE BY RATE CLASS

Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	PROPOSED INCREASE ($000s)	% Increase	% of Total
Schedule R	$129,555.8	$140,331.1	$10,775.3	8.32%	40.1%
Schedule G	$33,904.1	$36,723.9	$2,819.8	8.32%	10.5%
Schedule J	$95,497.8	$104,623.3	$9,125.5	9.56%	34.0%
Schedule H	$4,804.9	$5,204.5	$399.6	8.32%	1.5%
Schedule P	$58,135.4	$61,761.8	$3,626.4	6.24%	13.5%
Schedule F	$1,249.7	$1,379.6	$129.9	10.39%	0.5%
Total Sales Revenues	$323,147.7	$350,024.2	$26,876.5	8.32%	100.0%
Other Operating Revenues	$925.4	$1,100.8	$175.4	18.95%	
Total Revenues	$324,073.1	$351,125.0	$27,051.9	8.35%	

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

ALLOCATION OF RATE INCREASE BASED ON EQUAL CLASS ROR

Rate Class	Sales Revenues at Present Rates	Rev Requirements at Equal ROR	REVENUE INCREASE			CLASS RATES OF RETURN	
	($000s)	($000s)	($000s)	% Increase	% of Total	At Present Rates (%)	At Equal ROR (%)
Schedule R	$129,555.8	$149,305.3	$19,749.5	15.24%	73.5%	2.22%	8.61%
Schedule G	$33,904.1	$33,744.2	($159.9)	-0.47%	-0.6%	8.80%	8.61%
Schedule J	$95,497.8	$100,676.8	$5,179.0	5.42%	19.3%	5.52%	8.60%
Schedule H	$4,804.9	$5,089.7	$284.8	5.93%	1.1%	5.51%	8.61%
Schedule P	$58,135.4	$59,799.0	$1,663.6	2.86%	6.2%	6.53%	8.61%
Schedule F	$1,249.7	$1,409.2	$159.5	12.76%	0.6%	2.81%	8.61%
Total Sales Revenues	$323,147.7	$350,024.2	$26,876.5	8.32%	100.1%		
Other Operating Revenues	$925.4	$1,100.8	$175.4	18.95%			
TOTAL SYSTEM	$324,073.1	$351,125.0	$27,051.9	8.35%		4.44%	8.61%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

COMPARISON OF CLASS REVENUE REQUIREMENTS AT PRESENT RATES, AT PROPOSED RATES AND AT EQUAL RATES OF RETURN

Rate Class	Sales Revenues at Present Rates ($000s)	Sales Revenues at Proposed Rates ($000s)	Sales Revenues at Equal ROR ($000s)	CLASS RATES OF RETURN: At Present Rates (%)	CLASS RATES OF RETURN: At Proposed Rates (%)	CLASS RATES OF RETURN: At Equal ROR (%)
Schedule R	$129,555.8	$140,331.1	$149,305.3	2.22%	5.71%	8.61%
Schedule G	$33,904.1	$38,723.9	$33,744.2	8.80%	12.54%	8.61%
Schedule J	$95,497.8	$104,623.3	$100,676.8	5.52%	10.98%	8.60%
Schedule H	$4,804.9	$5,204.5	$5,089.7	5.51%	9.86%	8.61%
Schedule P	$58,135.4	$61,761.8	$59,799.0	6.53%	11.08%	8.61%
Schedule F	$1,249.7	$1,379.6	$1,409.2	2.81%	7.52%	8.61%
Total Sales Revenues	$323,147.7	$350,024.2	$350,024.2			
Other Operating Revenues	$925.4	$1,100.8	$1,100.8			
TOTAL SYSTEM	$324,073.1	$351,125.0	$351,125.0	4.44%	8.61%	8.61%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$45,407.1	37.12%	$74,676.1	37.98%	$20,247.9	65.10%	$140,331.1	40.09%
Schedule G	$12,557.7	10.27%	$16,919.6	8.61%	$7,246.5	23.30%	$36,723.8	10.49%
Schedule J	$40,864.9	33.41%	$61,032.4	31.04%	$2,726.1	8.77%	$104,623.4	29.89%
Schedule H	$2,009.4	1.64%	$2,961.9	1.51%	$233.3	0.75%	$5,204.6	1.49%
Schedule P	$20,895.8	17.08%	$40,262.2	20.48%	$603.8	1.94%	$61,761.8	17.65%
Schedule F	$579.4	0.47%	$756.1	0.38%	$44.1	0.14%	$1,379.6	0.39%
TOTAL	$122,314.3	99.98%	$196,608.3	99.99%	$31,101.7	100.01%	$350,024.3	100.01%
PERCENT OF TOTAL	34.94%		56.17%		8.89%		99.99%	

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT PROPOSED RATES

	Unit Cost Components At Proposed Rates			
Rate Class	Unit Demand Cost ($/kW/mo.)	Unit Energy Cost (¢/kWh)	Unit Customer Cost ($/Customer/mo.)	Total Unit Cost (¢/kWh)
Schedule R	$13.42	17.151	$27.49	32.230
Schedule G	$24.50	17.265	$55.97	37.473
Schedule J	$37.28	17.197	$145.72	29.480
Schedule H	$38.25	17.220	$73.63	30.259
Schedule P	$43.78	16.910	$824.90	25.939
Schedule F	$57.33	17.184	$28.74	31.355
TOTAL	$22.10	17.126	$34.94	30.490

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF COST COMPONENTS BY RATE CLASS AT EQUAL ROR

Rate Class	COST COMPONENTS AT PROPOSED RATES							
	DEMAND COSTS		ENERGY COSTS		CUSTOMER COSTS		TOTAL COSTS	
	($000s)	(%)	($000s)	(%)	($000s)	(%)	($000s)	(%)
Schedule R	$51,794.9	42.65%	$74,871.5	38.10%	$22,638.9	70.63%	$149,305.3	42.66%
Schedule G	$10,814.0	8.90%	$16,860.2	8.58%	$6,070.0	18.94%	$33,744.2	9.64%
Schedule J	$37,280.3	30.70%	$60,903.3	30.99%	$2,493.2	7.78%	$100,676.8	28.76%
Schedule H	$1,910.9	1.57%	$2,958.6	1.51%	$220.2	0.69%	$5,089.7	1.45%
Schedule P	$19,039.3	15.68%	$40,173.5	20.44%	$586.2	1.83%	$59,799.0	17.08%
Schedule F	$606.4	0.50%	$756.8	0.39%	$46.0	0.14%	$1,409.2	0.40%
TOTAL	$121,445.8	100.00%	$196,523.9	100.01%	$32,054.5	100.01%	$350,024.2	99.99%
PERCENT OF TOTAL	34.70%		56.15%		9.16%		100.01%	

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

SUMMARY OF UNIT COST COMPONENTS BY RATE CLASS AT EQUAL ROR

	Unit Cost Components At Equalized Rates of Return			
Rate Class	Unit Demand Cost	Unit Energy Cost	Unit Customer Cost	Total Unit Cost
	($/kW/mo.)	(¢/kWh)	($/Customer/mo.)	(¢/kWh)
Schedule R	$15.30	17.196	$30.74	34.292
Schedule G	$21.10	17.204	$46.88	34.433
Schedule J	$34.01	17.161	$133.27	28.368
Schedule H	$36.38	17.201	$69.51	29.591
Schedule P	$39.89	16.873	$800.82	25.115
Schedule F	$60.00	17.201	$29.95	32.027
TOTAL	$21.95	17.119	$36.01	30.490

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL
SUMMARY OF ALLOCATION FACTORS

ALLOCATION BASIS		Schedule R	Schedule G	Schedule J	Schedule H	Schedule P	Schedule F	Total
Demand Allocation Factors:								
Average-Excess Demand	*D1*	*42.097%*	*8.726%*	*30.757%*	*1.572%*	*16.352%*	*0.496%*	*100.00%*
Class Peak Demand	D2	44.225%	8.806%	30.634%	1.607%	14.172%	0.556%	100.00%
Composite NCD	D3	57.829%	9.943%	25.347%	1.415%	5.055%	0.411%	100.00%
Energy Allocation Factors:								
Gross Input	E1	38.106%	8.577%	30.986%	1.505%	20.440%	0.385%	100.00%
Customer Allocation Factors:								
Primary Lines	C1	78.809%	16.625%	3.724%	0.522%	0.157%	0.164%	100.00%
Secondary Lines	C2	81.361%	15.304%	2.645%	0.413%	0.108%	0.170%	100.00%
Transformers	C3	49.277%	38.289%	10.277%	1.280%	0.775%	0.103%	100.00%
Services	C4	78.308%	16.519%	4.237%	0.495%	0.277%	0.163%	100.00%
Meter	C5	65.238%	14.794%	17.202%	0.971%	1.659%	0.136%	100.00%
Cust Acct Fct	C6	77.942%	17.264%	3.940%	0.463%	0.182%	0.210%	100.00%
Bad Debt	C7	73.000%	14.000%	13.000%	0.000%	0.000%	0.000%	100.00%
Cust Serv Fct	C8	53.000%	7.000%	23.000%	1.000%	16.000%	0.000%	100.00%
Avg Cust	C10	82.742%	14.546%	2.102%	0.356%	0.082%	0.173%	100.00%

Source: HELCO-RWP-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
TEST YEAR 2006 DOCKET NO. 05-0315 REBUTTAL

COMPARISON OF CLASS REVENUES AND CLASS RATES OF RETURN
AT PRESENT RATES

	DIRECT TESTIMONY			REBUTTAL TESTIMONY		
Rate Class	Sales Revenue @Present Rates	Class Rate of Return	Rate of Return Index	Sales Revenue @Present Rates	Class Rate of Return	Rate of Return Index
	($000s)	(%)	(%)	($000s)	(%)	(%)
R	$129,577.5	1.85%	45%	$129,555.8	2.22%	50%
G	$33,909.0	8.02%	196%	$33,904.1	8.80%	198%
J	$95,527.2	5.52%	135%	$95,497.8	5.52%	124%
H	$4,805.7	4.83%	118%	$4,804.9	5.51%	124%
[illegible]	$58,114.9	6.02%	147%	$58,135.4	6.53%	147%
F	$1,249.9	2.53%	62%	$1,249.7	2.81%	63%
Total Sales Rev.	$323,184.2			$323,147.7		
Other Oper. Rev.	$904.4			$925.4		
Total Revenues	$324,088.6	4.10%	100%	$324,073.1	4.44%	100%

Source: HELCO-2001; HECO-R-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
TEST YEAR 2006 DOCKET NO. 05-0315 REBUTTAL

COMPARISON OF CLASS REVENUES AND CLASS RATES OF RETURN
AT PROPOSED RATES

	DIRECT TESTIMONY			REBUTTAL TESTIMONY		
Rate Class	Sales Revenue @Proposed Rates	Class Rate of Return	Rate of Return Index	Sales Revenue @Proposed Rates	Class Rate of Return	Rate of Return Index
	($000s)	(%)	(%)	($000s)	(%)	(%)
R	$141,557.6	5.63%	65%	$140,331.1	5.71%	66%
G	$37,044.1	12.08%	140%	$36,723.9	12.54%	146%
J	$105,672.6	11.51%	133%	$104,623.3	10.98%	128%
H	$5,250.0	9.61%	111%	$5,204.5	9.86%	115%
P	$62,146.6	11.01%	127%	$61,761.8	11.08%	129%
F	$1,393.6	7.68%	89%	$1,379.6	7.52%	87%
Total Sales Rev.	$353,064.5			$350,024.2		
Other Oper. Rev.	$955.2			$1,100.8		
Total Revenues	$354,019.7	8.65%	100%	$351,125.0	8.61%	100%

Source: HELCO-2001; HECO-R-2001.

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE R - RESIDENTIAL SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS (MWH)	UNIT PRICE ¢/KWH	REVENUES $1000s	UNIT PRICE ¢/KWH	REVENUES $1000s
ENERGY CHARGE:					
NON-FUEL ENERGY CHG.	435400	11.5238	50,174.6		
BASE FUEL CHG.	435400	7.6132	33,147.9		
SUBTOTAL ENERGY			83,322.5		
ENERGY CHARGE:					
BASE FUEL CHG.	435400			16.7455	72,909.9
NON-FUEL ENERGY CHG.					
0 - 300 kWh	198136			12.5244	24,815.3
300 - 1000 kWh	191119			14.6349	27,970.1
Over 1000 kWh	46145	435400		15.4656	7,136.6
SUBTOTAL ENERGY					132,831.9
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
Single Phase Svc.	736167	10.00	7,361.7	10.00	7,361.7
Three Phase Svc.	309	14.50	4.5	14.50	4.5
SUBTOTAL CUSTOMER			7,366.2		7,366.2
SUBTOTAL ENERGY + CUSTOMER CHARGES			90,688.7		140,198.1
ADJUSTMENTS:					
RENEWABLE CREDIT					189.6
EMPLOYEE DISC.			(342.7)		(188.0)
10% APT-HSE.			(86.2)		(86.4)
LIHEAP ADJ.			0.0		(72.9)
MINIMUM ADJ.			118.7		290.7
SUBTOTAL			(310.2)		133.0
UNADJUSTED BASE REV.:			90,378.5		140,331.1
	(MWH)				
FOA, CENTS/KWH	435400	8.99800	39,177.3	0.000	0.0
TOTAL SALES REVENUES			129,555.8		140,331.1
FCS, %			0.0	0.000	0.0
TOTAL REVENUES			129,555.8		140,331.1

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE G - GENERAL SERVICE NON-DEMAND
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING	PRESENT RATES		PROPOSED RATES	
	UNITS MWH	UNIT PRICE ¢/KWH	REVENUES $1000S	UNIT PRICE ¢/KWH	REVENUES $1000S
ENERGY CHARGE:	98,000.0	21.3604	20,933.2	32.2535	31,608.4
	BILLS	$/BILL		$/BILL	
CUSTOMER CHARGE:					
1 PHASE	103,078	28.00	2,886.2	35.00	3,607.7
3 PHASE	26,390	48.00	1,266.7	57.00	1,504.2
SUBTOTAL	129,468		4,152.9		5,111.9
POWER FACTOR ADJ.			0		0.0
MINIMUM BILL ADJ.			0		0.0
SCHEDULE E ADJ.					-39.1
RENEWABLE CREDIT					42.7
Other Base Adj.			0.0		0.0
SUBTOTAL			0.0		3.6
Total Base Rev.			25,086.1		36,723.9
FCS, %		0	0.0	0	0.0
Other % Adj.					
SUBTOTAL			0		0
FOA, ¢/KWH	98000	8.9980	8,818.0	0.0000	0.0
Other ¢/KWH Adj					
SUBTOTAL			8,818.0		0.0
TOTAL REVENUES			33,904.1		36,723.9

Source: *HELCO-RWP-302*

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE J - GENERAL SERVICE DEMAND
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS MWH	UNIT PRICE ¢/KWH	REVENUES $1000S	BILLING UNITS MWH	UNIT PRICE ¢/KWH	REVENUES $1000S
ENERGY CHARGE:						
0 - 200 KWH/KW	211,908.4	16.4579	34,875.7	217,081.1	26.1538	56,775.0
201 - 400 KWH/KW	112,450.2	14.2407	16,013.7	107,147.6	23.9367	25,647.6
> 400 KWH/KW	30,541.4	13.2397	4,043.6	30,671.3	22.9357	7,034.7
SUBTOTAL	354,900.0		54,933.0	354,900.0		89,457.3
	BILLS	$/BILL		BILLS	$/BILL	
CUSTOMER CHARGE:						
1 PHASE	2,679	33.00	88.4	2,679	39.00	104.5
3 PHASE	16,029	56.00	897.6	16,029	65.00	1,041.9
SUBTOTAL	18,708		986.0	18,708		1,146.4
DEMAND CHARGE:	1,211,882.0	7.00	8,483.2	1,245,222.0	12.00	14,942.7
ADJUSTMENTS:						
TRANS VOLT ADJ (TP)			0.0			0.0
PRI VOLT ADJ (DP)			(266.4)			(221.8)
PRI VOLT ADJ (DS)			(12.2)			(3.0)
PF ADJ			(16.9)			(18.4)
MINIMUM BILL ADJ.			0.0			0.0
RENEWABLE CREDIT						154.6
SCHEDULE E ADJ.			0.0			(90.5)
Rider Adj.			(542.8)			(744.0)
SUBTOTAL			(838.3)			(923.1)
Total Base Revenue:			63,563.9			104,623.3
FIRM CAP. SURCHRG. %		0.000	0.0		0.000	0.0
Other % Adj.						
	MWH			MWH		
FOA, ¢/KWH	354,900.0	8.998	31,933.9	354,900.0	0.000	0.0
Other ¢/KWH Adj.						
Total Rev. Adj.			31,933.9			0.0
Other Adj.						
TOTAL SALES REV.			95,497.8			104,623.3

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE H - COMMERCIAL COOKING, HEATING,
AIR CONDITIONING & REFRIGERATION SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING	PRESENT RATES		PROPOSED RATES	
	UNITS MWH	UNIT PRICE CENTS/KWH	REVENUES $1000s	UNIT PRICE CENTS/KWH	REVENUES $1000s
ENERGY CHARGE:	17200	15.9189	2,738.1	26.4183	4,543.9
	KW	$/KW		$/KW	
CAPACITY CHARGE:	57,328	7.00	401.3	9.00	516.0
CUSTOMER CHARGE:	BILLS	$/BILL/MO		$/BILL/MO	
1 PHASE	1,456	28.00	40.8	34.00	49.5
3 PHASE	1,712	45.00	77.0	54.00	92.4
SUBTOTAL	3,168		117.8		141.9
UNADJUSTED BASE REV.			3,257.2		5201.8
ADJUSTMENTS:	MWH				
FOA, Cents/kwh	17200	8.998	1,547.7	0	0.0
SUBTOTAL			1547.7		0.0
SCHEDULE E ADJ.			0.0		-4.8
RENEWABLE CREDIT					7.5
UNADJ. TOTAL REV.			4,804.9		5204.5
FCS, %		0	0.0	0	0.0
TOTAL REVENUES			4,804.9		5,204.5

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE P - LARGE POWER SERVICE
ESTIMATE OF TEST-YEAR REVENUES
DOCKET NO. 05-0315 TEST-YEAR 2006

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	CENTS/KWH		CENTS/KWH	
0 - 200 KWH/KW	97,978	15.2290	14,921.1	24.0599	23,573.4
201 - 400 KWH/KW	93,216	13.0488	12,163.6	21.8797	20,395.4
> 400 KWH/KW	46,906	12.0458	5,650.2	20.8767	9,792.4
SUBTOTAL	238,100		32,734.9		53,761.2
DEMAND CHARGE:	(KW)	$/KW		$/KW	
0 - 500 KW	318,134	11.25	3,579.0	19.50	6,203.6
> 500 KW	176,093	10.75	1,893.0	19.00	3,345.8
SUBTOTAL	494,227		5,472.0		9,549.4
	BILLS	$/BILL		$/BILL	
CUSTOMER CHARGE:	732	375.00	274.5	500.00	366.0
ADJUSTMENTS:					
PF			(515.8)		(854.7)
TP			0.0		0.0
DP			(1,113.6)		(922.6)
DS			(31.8)		(7.9)
RIDER T			0		0
RIDER M			(109.0)		(188.0)
Schedule U			0		0.0
RENEWABLE CREDIT					103.7
SCHEDULE E ADJ.			0.0		(45.4)
SUBTOTAL			(1,770.2)		(1,914.9)
Base Revenue:			36,711.2		61,761.7
FCS ADJ.		0	0.0	0	0.0
FUEL OIL ADJ.	238100	8.998	21,424.2	0.000	0.0
SUBTOTAL			21,424.2		0.0
TOTAL REVENUES			58,135.4		61,761.7

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE F - STREET LIGHTING SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING	PRESENT RATES		PROPOSED RATES	
	UNITS (MWH)	UNIT PRICE ¢/KWH	REVENUES $1000S	UNIT PRICE ¢/KWH	REVENUES $1000S
ENERGY CHARGE:					
0 - 150 KWH/KW	1,922.6	22.7311	437.0	34.6893	666.9
> 150 KWH/KW	2,477.4	16.5301	409.5	28.4883	705.8
SUBTOTAL	4,400.0		846.5		1,372.7
ADJUSTMENTS:					
MINIMUM CHARGE:			7.3		6.5
RENEWABLE CREDIT					1.9
UNADJUSTED TOTAL REV.:			853.8		1,381.1
FUEL OIL ADJ.:	4,400.0	8.998	395.9	0.000	0.0
SUBTOTAL			395.9		0.0
EMP. DISC ADJ.			0.0		-1.5
FIRM CAP. SURCHRG. %		0.000	0	0.000	0
TOTAL REVENUES			1,249.7		1,379.6

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315, TEST-YEAR 2006 REBUTTAL

DETERMINATION OF BASE FUEL ENERGY CHARGE

In Cents Per kWh

L1	Weighted Base Central Station + Wind/Hydro Generation Cost	6.83485	HELCO-R-2204, line 31
L2	Revenue Tax Requirements Multiplier	1.0975	HELCO-R-2204, line 33
L3 = L1 * L2	Base Central Station + Wind/Hydro Generation Cost at Revenue Level	7.50125	
L4	Weighted Base DG (Distributed Generation) Energy Cost	0.00149	HELCO-R-2204, line 40
L5	Loss Factor	1.090	HELCO-R-2204, line 42
L6	Revenue Tax Requirements Multiplier	1.0975	HELCO-R-2204, line 43
L7 = L4*L5*L6	Base DG Energy Cost at Revenue Level	0.00178	
L8	Weighted Base Purchased Energy Cost	7.72605	HELCO-R-2204, line 81
L9	Loss Factor	1.090	HELCO-R-2204, line 83
L10	Revenue Tax Requirements Multiplier	1.0975	HELCO-R-2204, line 84
L11 = L8*L9*L10	Base Purchased Energy Cost at Revenue Level	9.24248	
L12 = L3+L7+L11	Base Fuel Energy Charge	16.7455	

Superseding Revised Sheet No. 50
Effective June 1, 2001

REVISED SHEET NO. 50
Effective

RATE SCHEDULES

The following listed sheets contain all rates in effect on and after the date indicated thereon subject to the Rules and Regulations of the Company applicable thereto:

Sheet	Schedule	Effective Date	Character of Service
50.1	Firm Capacity Surcharge		All Schedules Except Schedule Q
	(PAGES 50.2 - 50.3 NOT ASSIGNED)		
51	"R"		Residential Service
51A	"		"
52	"G"		General Service Non-Demand
52A	"		"
52B	"J"		General Service Demand
52C	"		"
52D	"		"
53	"H"		Commercial Cooking and Heating Service
53A	"		Commercial Cooking and Heating Service
54	"P"		Large Power Service
54A	"		"
54B	"		"
55	"F"		Street Light Service
55A	"		"
56	"U"		Time-of-Use Service
56A	"U"		"
56B	"U"		"
57	"E"		Electric Service for Employees
	(PAGES 58 - 59 NOT ASSIGNED)		
60	Rider M		Off-Peak & Curtailable Rider
60A	"		"
60B	"		"
60C	"		"

Superseding Revised Sheet No. 50A
Effective April 1, 2006

REVISED SHEET NO. 50A
Effective

RATE SCHEDULES

Sheet	Schedule	Effective Date	Character of Service
61	Rider I		Interruptible Contract Rider
62	Rider T		Time-of-Day Rider
62A	Rider T		Time-of-Day Rider
63	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63A	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
63B	Energy Cost Adjustment Clause		All Schedules Except Schedule Q
64	IRP Cost Recovery Provision		All Schedules Except Schedule Q
65	IRP Cost Recovery Provision		All Schedules Except Schedule Q
66	IRP Cost Recovery Provision		All Schedules Except Schedule Q
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70	Rider A		Standby Service Rider
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70I	Rider A		Standby Service Rider
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Superseding Revised Sheet No. 50B
Effective June 5, 2001

REVISED SHEET NO. 50B
Effective

RATE SCHEDULES

Sheet	Schedule	Effective Date	Character of Service
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71A	TOU-R		Residential Time-of-Use
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72	TOU-G		Small Commercial Time-of-Use
72A	TOU-G		Small Commercial Time-of-Use
72B	TOU-G		Small Commercial Time-of-Use
73	TOU-J		Commercial Time-of-Use
73A	TOU-J		Commercial Time-of-Use
73B	TOU-J		Commercial Time-of-Use
74	TOU-P		Large Power Time-of-Use
74A	TOU-P		Large Power Time-of-Use
74B	TOU-P		Large Power Time-of-Use
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81	"Q"		Purchases From Qualifying Facilities-100 KW or Less
81A	"Q"		Purchases From Qualifying Facilities-100 KW or Less
82	Green Pricing Program Provision		Green Pricing
82A	Green Pricing Program Provision		Green Pricing

Superseding Revised Sheet No. 50.1
Effective February 15, 2001

Revised Sheet NO. 50.1
Effective

FIRM CAPACITY SURCHARGE

Supplement To

Schedule "R"	-	Residential Service
Schedule "E"	-	Electric Service for Employees
Schedule "G"	-	General Service Non-Demand
Schedule "J"	-	General Service Demand
Schedule "H"	-	Commercial Cooking and Heating Service
Schedule "P"	-	Large Power Service
Schedule "F"	-	Street Light Service
Schedule "U"	-	Time-of-Use Service
Schedule "TOU-R"	-	Residential Time-of-Use Service
Schedule "TOU-G"	-	Small Commercial Time-of-Use Service
Schedule "TOU-J"	-	Commercial Time-of-Use Service
Schedule "TOU-P"	-	Large Power Time-of-Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "P", "F", "U", "TOU-R", "TOU-G", "TOU-J" and "TOU-P" are applicable, except that the total base rate charges for each billing period shall be increased by the following Firm Capacity Surcharge approved by the Public Utilities Commission:

FIRM CAPACITY SURCHARGE:

All Rate Schedules 0 percent

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges and adjustments, excluding the energy cost adjustment, Residential DSM Adjustment, Commercial and Industrial DSM Adjustment, and IRP Adjustment.

ADJUSTMENT TO SURCHARGE: (To be added to Firm Capacity Surcharge)

The above Firm Capacity Surcharge is based on recovering the Puna Geothermal Venture's firm capacity cost and related revenue taxes totaling _________ over estimated base revenues of_______ for the year_____. In order to reconcile any differences that may occur between the above costs to be recovered and the revenues received from the above surcharge, recorded revenues will be compared with the above costs on quarterly basis. If there is a variance between the recorded revenues from the surcharge and the costs to be recovered, a reconciliation adjustment, lagged by two months, will be made to the above surcharge.

(REVISED SHEET NOS. 50.2 & 50.3 - NOT ASSIGNED)

Superseding Revised Sheet No. 51
Effective February 15, 2001

REVISED SHEET NO. 51
Effective

SCHEDULE "R"

Residential Service

Availability:

Applicable to residential lighting, heating, cooking, air conditioning and power in a single family dwelling unit metered and billed separately by the Company. This schedule does not apply where a residence and business are combined.

Service will be delivered at secondary voltages as specified by the Company.

RATE:

CUSTOMER CHARGE:

Single phase service - per month	$10.00
Three phase service - per month	$14.50

NON-FUEL ENERGY CHARGE (To be added to Customer Charge)

First 300 kWhr per month - per kWhr	12.5244 ¢
Next 700 kWhr per month - per kWhr	14.6349 ¢
All kWhr over 1,000 kWhr per month- per kWhr	15.4656 ¢

BASE FUEL/ENERGY CHARGE (To be added to Customer Charge and Non-Fuel Energy Charge)

All kWhr per month - per kWhr	16.7455 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer Charge, Energy Charge, and energy cost adjustment.

Low Income Home Energy Assistance Program (LIHEAP):

For customers receiving bill credits under LIHEAP, the Non-Fuel Energy Charge is 12.5244 ¢/kWh for all kWhr per month.

Superseding Revised Sheet No. 51A
Effective March 15, 1991

REVISED SHEET NO. 51A
Effective

Schedule "R" (Continued)

Minimum Charge:

The minimum monthly charge shall be the greater of $20.00 per month or the calculated bill based on 15% of the highest kWh usage in the previous 11 months. The calculated bill shall include the Customer Charge, Non-Fuel Energy Charge, Base Fuel Energy Charge, and all applicable rate adjustments, including the Energy Cost Adjustment Clause and the Integrated Resource Planning Cost Recovery Provision. Schedule R customers served under Rule No. 18, Net Energy Metering or who receive bill credits under the Low Income Home Energy Assistance Program shall be exempt from the minimum bill 15% ratchet calculation such that only the $20.00 per month Minimum Charge applies.

Apartment House Collection Arrangement:

Any apartment owner having three or more apartments at one location, each apartment being separately metered and billed on the above rate, may elect to accept a discount of ten percent (10%) of the amount of bills rendered for each apartment, but not to exceed $5.50 per month for each apartment, upon entering into the following collection agreement with the Company under the following terms and conditions:

1. All accounts shall be kept in the name of the apartment house owner who shall assume the responsibility for the prompt payment of all bills.

2. All accounts shall remain active at all times and, though vacant, shall be subject to the minimum charge. Individual apartments cannot be added to or deleted from this agreement more often than once in twelve months.

3. The Company will render individual bills for each apartment on a regular billing period basis and will also furnish a statement showing gross and net billings.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 52
Effective February 15, 2001

REVISED SHEET NO. 52
Effective

SCHEDULE "G"

General Service Non-Demand

Availability:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter.

When the customer's load exceeds 5,000 kilowatthours per month three times in a twelve-month period, or in the opinion of the Company, the load will exceed 25 kilowatts of demand, a demand meter will be installed and the customer's billing will be transferred to Schedule "J" beginning with the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company. Service supplied at primary voltage shall be subject to the special terms and conditions set forth below.

RATE:

CUSTOMER CHARGE:

Single phase service - per month	$35.00
Three phase service - per month	$57.00

ENERGY CHARGE: (To be added to Customer Charge)

All kWhr per month - per kWhr	32.2535 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer and Energy Charges, and energy cost adjustment.

Minimum Charge: Customer Charge

Superseding Revised Sheet No. 52A
Effective October 9, 1992

Revised Sheet NO. 52A
Effective

Schedule "G" (Continued)

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage of 2400 volts or more, the above energy charge will be decreased by 2.5%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customers' transformers, the above energy charge will be decreased by 0.6%.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SCHEDULE "J"

General Service Demand

Availability:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kilowatts but are less than 200 kilowatts per month, and supplied through a single meter.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company. Service supplied at primary voltage shall be subject to the special terms and conditions set forth below.

This Schedule is closed to new customers with the kW demand equal to or greater than 200 kW after ____, 2006. Existing customers with maximum measured kW demand equal to, or greater than 200 kW per month may continue to receive service under this Schedule, until the customer transfers to other applicable rate schedule.

RATE:

CUSTOMER CHARGE:

Single phase service - per month	$39.00
Three phase service - per month	$65.00

DEMAND CHARGE: (To be added to Customer Charge)

All kW of billing demand - per kW	$12.00

ENERGY CHARGE: (To be added to Customer and Demand Charges)

First 200 kWhr/month/kW of billing demand - per kWhr	26.1538 ¢
Next 200 kWhr/month/kW of billing demand - per kWhr	23.9367 ¢
Over 400 kWhr/month/kW of billing demand - per kWhr	22.9357 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Superseding Revised Sheet No. 52C
Effective February 15, 2001

REVISED SHEET NO. 52C
Effective

Schedule "J" (Continued)

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and Demand Charges. The Demand Charge shall be computed with the above demand charge applied to the kilowatts of billing demand, but not less than $300.00 per month. The kilowatts of billing demand for the minimum charge calculation each month shall be the highest of the maximum demand for such month, the greatest maximum demand for the preceding eleven months, or 25 kw.

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month or the mean of current monthly maximum demand and the greatest maximum demand for the preceding eleven months, whichever is higher, but not less than the minimum billing demand of 25 kilowatts.

Power Factor:

For customers with maximum measured demands in excess of 200 kilowatts per month for any one time within a twelve-month period, the following power factor adjustment will apply to the above energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the energy and demand charges as computed under the above rates will be decreased or increased, respectively, by 0.10%.

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Superseding Sheet No. 52D
Effective February 21, 1995

REVISED SHEET NO. 52D
Effective

Schedule "J" (Continued)

Primary Supply Voltage Service:

Where, at the option of the Company, service is delivered and metered at the primary supply line voltage of 2400 volts or more, the energy and demand charges as computed under the above rates will be decreased by 2.5%. When customers' transformers are adjacent to the delivery point, the Company may permit the customer to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customers' transformers, the above energy and demand charges will be decreased by 0.6%.

Term of Contract:

Not less than five years beginning from the service start date. If service is terminated before the end of the initial contract term, the customer shall be charged a termination fee equal to the total connection costs incurred by the Company to service the customer less customer advance and/or contribution paid by the Customer.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 53
Effective February 15, 2001

REVISED SHEET NO. 53
Effective

SCHEDULE "H"

Commercial Cooking and Heating Service

Availability:

Applicable only to commercial cooking, heating (including heat pump waterheaters), air conditioning and refrigeration service. For new customers after October 9, 1992, Schedule H will be applicable only to commercial cooking and heating service including heat pump waterheaters. This schedule applies only where the voltage supplied by the Company is less than 600 volts. This rate is closed to new customers after _____, 2006.

RATE:

CUSTOMER CHARGE:

Single phase service - per month	$34.00
Three phase service - per month	$54.00

DEMAND CHARGE: (To be added to Customer Charge)

$9.00 per month per billing kw of connected load, but in no case less than $9.00 per month.

ENERGY CHARGE: (To be added to Customer and Demand Charges)

All kWhr per month - per kWhr	26.4183 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Minimum Charge:

The minimum monthly charge shall be the sum of Customer and Demand charges.

Superseding Revised Sheet No. 53A
Effective October 9, 1992

REVISED SHEET NO. 53A
Effective

Schedule "H" (Continued)

Determination of Connected Load:

The total connected load for billing purposes shall be:

A. The sum of:

1) The total connected motor load.
2) 50% of the connected heating load exclusive of cooking and all-electric resistance and heat pump waterheating, and
3) the connected all-electric waterheating load in excess of one-sixth kilowatt per gallon of storage capacity; or

B. When the load is 25 kW or more the billing kW may be determined by measured demand. The maximum demand for each month shall be the maximum average load during any fifteen-minute period as indicated by a demand meter. The kilowatts of billing demand for each month shall be the highest of maximum demand for such month, the greatest maximum demand for the preceding eleven months, or 25 kilowatts. Measured demand service under this schedule will be referred to as Schedule "K" service. The Schedule K service will be closed to new customers after October 9, 1992.

The total connected load will be determined to the nearest one-tenth kW.

Term of Contract:

Not less than one year.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 54
Effective February 15, 2001

REVISED SHEET NO. 54
Effective

SCHEDULE "P"

Large Power Service

Availability:

Applicable to large light and/or power service loads equal or greater than 200 kilowatts, supplied and metered at a single voltage and delivery point.

This Schedule is closed to new customers with the kW demand less than 200 kW after ____, 2006. Existing customers with maximum measured kW demand less than 200 kW per month may continue to receive service under this Schedule, until the customer transfers to other applicable rate schedule.

RATE:

CUSTOMER CHARGE - per month	$500.00

DEMAND CHARGE - (To be added to Customer Charge)

First 500 kW of billing demand - per kW	$19.50
Over 500 kW of billing demand - per kW	$19.00

ENERGY CHARGE: (To be added to Customer and Demand Charges)

First 200 kWhr/month/kW of billing demand-per kWhr	24.0599 ¢
Next 200 kWhr/month/kW of billing demand-per kWhr	21.8797 ¢
Over 400 kWhr/month/kW of billing demand-per kWhr	20.8767 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Minimum Charge:

The minimum monthly charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charges applied to kilowatts of billing demand.

Superseding Revised Sheet No. 54A
Effective March 15, 1991

REVISED SHEET NO. 54A
Effective

Schedule "P" (Continued)

Determination of Demand:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter. The billing demand for each month shall be the maximum demand for such month or the mean of current monthly maximum demand and the greatest maximum demand for the preceding eleven months, whichever is higher, but not less than the minimum billing demand of 200 kW.

The billing kW for the minimum charge calculation each month shall be the maximum demand for the month but not less than the greatest maximum demand for the preceding eleven months nor less than 200 kW.

Power Factor:

The above demand and energy charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the demand and energy charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%. The power factor will be computed to the nearest whole percent.

In no case, however, shall the power factor be taken as more than 100% for the purpose of computing the adjustment.

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	4.0%
Distribution voltage supplied without further transformation	2.5%

Metering will normally be at the delivery voltage. When customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Superseding Revised Sheet No. 54B
Effective March 15, 1991

REVISED SHEET NO. 54B
Effective

Schedule "P" (Continued)

Excessive Instantaneous Demands:

The maximum demand may be limited by contract. In order to guard against excessive instantaneous loads on its system, the Company reserves the right to install load limiting circuit breaker equipment on the customer's service to automatically limit the maximum demand to the contract capacity.

Term of Contract:

Contracts for service under this rate shall be for not less than one year and thereafter until cancelled by six months written notice given by either party.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 55
Effective February 15, 2001

REVISED SHEET NO. 55
Effective

SCHEDULE "F"

Street Light Service

Availability:

Applicable only to all-night service for street and highway lighting where the customer owns, maintains, and operates the lighting fixtures and all circuits and appurtenances on the customer's side of the delivery point. The service voltage shall be the available distribution voltage at the point of delivery.

RATE:

ENERGY CHARGE:

First 150 kWhr/month/kW of billing demand - per kWhr	34.6893 ¢
Over 150 kWhr/month/kW of billing demand - per kWhr	28.4883 ¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Energy Charge.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Energy Charge and energy cost adjustment.

Minimum Charge:

$35.00 per month per delivery point.

Determination of Energy and Demand:

Metered Service:

The maximum demand for each month shall be the maximum average load in kW during any fifteen-minute period as indicated by a demand meter or by test. The kilowatts of billing demand for each month shall be the maximum demand for such month but not less than 50% of greatest maximum demand for the preceding eleven months.

The monthly billing kWh energy shall be as metered at the point of delivery.

Superseding Revised Sheet No. 55A
Effective March 15, 1991

REVISED SHEET NO. 55A
Effective

Schedule "F" (Continued)

Unmetered Service:

The billing demand for each month shall be the connected kW load of the lamp and appurtenances rounded to nearest one-tenth kilowatt.

The monthly kWh energy for billing purposes shall be the kW billing demand times 340 hours.

Special Terms and Conditions:

Service will be metered at the point of delivery except as provided for below.

Multiple street lighting lamps may be individually served unmetered at secondary voltage along public streets and highways when, (1) in an overhead area, secondary voltage is available on the lamp pole or (2), in an underground area, secondary voltage is available along the public street. The total connected lamp load per connection point shall not exceed 2 kW. A one-year contract is required for service under this provision and each such contract will remain in effect from year to year thereafter unless, after the first year, terminated by 30-days notice in writing. Each contract will constitute a point of delivery.

The customer will provide a switching device for each lamp to limit the annual burning time to not more than 4100 hours.

The charges in this schedule are based on the premise that secondary voltage is available at the point of delivery. If it is not available, the customer may take primary voltage or may make an advance to the Company in the estimated amount to make such service available.

No street lighting fixtures or facilities will be furnished by the Company under this schedule.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 56
Effective February 15, 2001

REVISED SHEET NO. 56
Effective

SCHEDULE U

TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 25 kilowatts and supplied and metered at a single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders "M", "T","I", Schedule TOU-J and Schedule TOU-P. This rate is closed to new customers after ____, 2006.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATE:

CUSTOMER CHARGE - per month	$200.00
DEMAND CHARGE - (To be added to Customer Charge)	
All On-Peak kWh of billing demand - per kW	$28.00
ENERGY CHARGE - (To be added to Customer and Demand Charges)	
All On-Peak kWhr per month - per kWhr	26.1538¢
All Off-Peak kWhr per month - per kWhr	21.1260¢

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy Charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Cost Recovery Provision shall be added to the Customer, Demand, and Energy Charges, and energy cost adjustment.

Superseding Revised Sheet No. 56A
Effective February 21, 1995

REVISED SHEET NO. 56A
Effective

Schedule "U" (Continued)

Minimum Charge:

The monthly minimum charge shall be the sum of the Customer and the Demand Charges. The Demand Charge shall be computed with the above demand charges applied to kilowatts of demand. The kilowatts of billing demand for the minimum charge of calculation for each month shall be the highest of the maximum on-peak demand for such month, but not less than 25 kW.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's energy consumption and peak load during the time-of-day rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The on-peak kilowatts of billing demand for each month shall be the maximum on-peak demand for such month, but not less than 25 kilowatts.

Power Factor:

For customers with on-peak or off-peak demands in excess of 200 kilowatts per month one time within a twelve-month period, the following power factor adjustment shall apply to the above energy and demand charges.

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates will be decreased or increased, respectively, by 0.15%.

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Special Terms and Conditions:

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Superseding Revised Sheet No. 56B
Effective February 21, 1995

REVISED SHEET NO. 56B
Effective

Schedule "U" (Continued)

Transmission voltage supplied without further transformation	4.0%
Distribution voltage supplied without further transformation	2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

TERM OF CONTRACT:

Not less than five years.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 57
Effective June 1, 1996

REVISED SHEET NO. 57
Effective

SCHEDULE "E"

Electric Service For Employees

AVAILABILITY:

Applicable to all regular full-time Company employees, Company retirees, members of the Company Board of Directors, and retirees of Hawaiian Electric Company, Inc. and Maui Electric Company, Ltd. who retired on or after January 1, 1996 and who are served by Hawaii Electric Light Company, Inc. This schedule is applicable to the above customers' residential electric service in a single family dwelling unit metered and billed separately by the Company, subject to the Special Terms and Conditions specified below. This schedule does not apply where a residence and business are combined.

RATE:

The rates applicable to service under this schedule shall be two-thirds (2/3) of the current effective Schedule R rates - Residential Service, for usage up to 825 kWh per month. Energy usage above 825 kWh shall be charged the full Schedule R energy rates.

Special Terms and Conditions:

1. "Regular full-time Company employee" is defined as an employee who has successfully completed any required probationary requirements, is hired for an indefinite period, and who works no less than 40 hours per week.
2. This schedule is applicable only to primary residences.
3. Availability of this schedule terminates six months after death of eligible employee, retiree, or member of the Board of Directors.

Rules and Regulations:

Service supplied under this schedule shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 60
Effective February 15, 2001

REVISED SHEET NO. 60
Effective

RIDER "M"

Off-Peak and Curtailable Rider

AVAILABILITY:

This Rider is available to customers served under rate Schedule "J" or "P" whose maximum measured demands prior to any load modifications effected under this rider, exceed 100 and 300 kilowatts, respectively. This Rider cannot be used in conjunction with Rider T, Rider I, Schedule U, Schedule TOU-J and Schedule TOU-P.

RATE:

A. Basic Rates:

The rates for service under this Rider shall be as specified under the regular Schedule "J" or "P", whichever is applicable except that the Minimum Charge and the determination of billing demand used in the calculation of demand and energy charges shall be as defined below, subject to the requirements of the Determination of Demand provision of the applicable rate schedule.

The customer shall select Option A - Off-Peak Service, or Option B - Curtailable Service:

OPTION A - OFF-PEAK SERVICE:

1) Any demand occurring during the off-peak period shall not be considered in determining the billing kW demand for each month, but shall be used in determining the excess off-peak charge. Only the maximum kW demand occurring during the on-peak period shall be used in the determination of the billing kW demand for the calculation of the demand charge, energy charge and minimum charge as specified in the regular Schedule J or P.

2) An Excess Off-Peak Charge of $1.00 per kilowatt shall be added to the regular rate schedule charges for each kilowatt that the maximum off-peak kW demand exceeds the maximum kW demand during the on-peak period.

3) For calculation of the excess off-peak charge for each month, the maximum off-peak demand and maximum demand during the on-peak period shall be the highest measured demands during the respective periods for such month.

Superseding Revised Sheet No. 60A
Effective February 15, 2001

REVISED SHEET NO. 60A
Effective

Rider "M" (Continued)

4) The time-of-use rating periods shall be defined as follows:

On-Peak Period 7 a.m. - 9 p.m. Fourteen hours, Daily

Off-Peak Period 9 p.m. - 7 a.m. Ten continuous hours, Daily

5) The monthly minimum charge shall be the sum of the customer charge and demand charge in the applicable rate schedule, and the Excess Off-Peak Charge and Time of Day Metering Charge specified below.

OPTION B - CURTAILABLE SERVICE:

1) A customer who chooses curtailable service shall curtail its kW load during the Company's curtailment hours, and shall specify the curtailable kW load. This curtailable load must be load that is normally operated during the Company's curtailment hours and must be at least 50 and 150 horsepower for motor loads under Schedules "J" and "P", respectively, or 50 and 150 kilowatts for other than motor loads. The Company may install a meter to measure the customer's curtailable load prior to start of curtailable service under this Rider.

2) For billing purposes, the curtailed demand shall be determined monthly as the difference between the maximum kW demand outside of the curtailment hours and the maximum kW demand during the curtailment hours measured for each month, but not to exceed the curtailable kW load specified in the customer's Rider M contract.

3) The customer shall choose one of the curtailment periods specified below. The billing demand under this curtailable service option shall be the normal billing demand under Schedule "J" or "P" reduced by:

Option 1) 75% of the curtailed demand if the curtailment period is fixed throughout the year from 5 p.m. to 9 p.m., Monday through Friday; or

Option 2) 40% of the curtailed demand if the curtailment period is two (2) consecutive hours as specified by the Company.

Superseding Revised Sheet No. 60B
Effective February 15, 2001

REVISED SHEET NO. 60B
Effective

Rider "M" - Continued

4) The monthly minimum charge shall be the sum of the customer charge and demand charge in the applicable rate schedule, and the Time-of-Day Metering Charge specified below.

Where the Company specifies the curtailment hours, the Company shall give the customer at least 30 days notice prior to changing the curtailment period.

B. TIME-OF-DAY METERING CHARGE:

The Company shall install a time-of-use meter to measure the customer's maximum kW load during the time-of-day rating periods and curtailment periods.

An additional time-of-day metering charge of $10.00 per month shall be assessed to cover the additional cost of installing, operating, and maintaining a time-of-use meter.

C. TERMS OF CONTRACT:

1. The initial term of contract shall be at least 3 years. Thereafter, the contract will be automatically renewed in 3-year increments until terminated by either party by a 30-day written notice.

2. A customer applying for service under this Rider shall sign a standard Rider M contract form with the Company.

3. The customer shall be allowed to take service under this Rider for a six-month trial period without penalty for termination within this period.

4. If the contract is terminated after the six months trial period, but before the first three-year period which begins from the start date of the customer's service under this Rider, the customer shall be assessed a termination charge equal to the last six months discount received under this Rider.

5. The customer may request a change of Rider options (Option A - Off-Peak Service or Option B - Curtailable Service) or curtailment hours (Options 1 or 2 under Curtailable Service) by providing a 30-day written notice to the Company. The change

Superseding Revised Sheet No. 60C
Effective February 15, 2001

REVISED SHEET NO. 60C
Effective

Rider "M" - Continued

will become effective after the next regular meter reading following the receipt of such written notice by the Company, provided however, the Company may not be required to make such change until 12 months of service has been rendered after the last change, unless a new or revised Rider has been authorized, or unless a customer's operating conditions have altered so as to warrant such change.

6. If under the curtailable service option the customer fails to curtail his maximum demand during the curtailment period three times within a twelve-month period, the Company may terminate the Rider M contract by a 30-day written notice to the customer. If service under this Rider is terminated due to the customer's failure to curtail his demand as provided in the contract, the customer shall be assessed a termination charge equal to the last six-months discount received under this Rider.

7. Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 61
Effective March 15, 1991

REVISED SHEET NO. 61
Effective

RIDER "I"

Interruptible Contract Rider

Availability:

This Rider is applicable to service supplied and metered at a single voltage and delivery point where 500 kw or greater is subject to disconnection by the utility under the terms and conditions as set forth in the contract agreement.

Rate:

Reduction in demand charge as set forth in a contract between the customer and the utility and approved by the Public Utilities Commission.

Term of Contract:

Not less than five years.

Superseding Revised Sheet No. 62
Effective February 21, 1995

REVISED SHEET NO. 62
Effective

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers in rate Schedule "J" or "P" but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, Schedule TOU-J and Schedule TOU-P. This rate is closed to new customers after ____, 2006.

TIME-OF-DAY RATING PERIODS:

The time-of-day rating periods under this Rider shall be as follows:

On-Peak Period: 7:00 a.m. - 9:00 p.m., daily
Off-Peak Period: 9:00 p.m. - 7:00 a.m., daily

RATES:

The rates for service under this Rider including the Customer Charge, Energy Charge, and Demand Charge shall be as specified in the regular rate schedule J or P, except that the following charges shall be added:

TIME-OF-DAY METERING CHARGE - per month	$10.00

TIME-OF-DAY ENERGY CHARGE ADJUSTMENT:

On-Peak Energy Surcharge	- all on-peak kWhr	+ 2.50¢
Off-Peak Energy Credit	- all off-peak kWhr	- 3.15¢

MINIMUM CHARGE:

The Minimum Charge shall be as specified under the regular rate schedule except that it shall include the Time-of-Day Metering Charge.

DETERMINATION OF DEMAND:

The Determination of Demand shall be as specified in the regular rate schedule, except that only the on-peak kW demand shall be used in the determination of the kilowatts of billing demand for the Demand Charge, the regular Energy Charge and the Minimum Charge calculations.

Superseding Revised Sheet No. 62A
Effective February 21, 1995

REVISED SHEET NO. 62A
Effective

Rider "T" (Continued)

VOLTAGE SERVICE AND POWER FACTOR ADJUSTMENTS:

The voltage service and power factor adjustments shall be as specified in the regular rate schedule.

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kWhr consumption and maximum kW demand during the time-of-use rating periods.

TERMS OF AGREEMENT:

The customer applying for service under this Rider shall sign a standard Rider T contract form with the Company. Service under this Rider shall not be less than five (5) years. The customer may terminate service under this Rider during the first six months without penalty. If the customer terminates service after the first six months but before the end of the first five-year period which begins from the start date of the customer's service under this Rider, the customer shall be charged a termination fee equal to the amount of the last six months of savings received under this Rider.

Superseding Revised Sheet No. 63
Effective February 15, 2001

Revised Sheet NO. 63
Effective

ENERGY COST ADJUSTMENT CLAUSE

Applicable To

Schedule "R"	-	Residential Service
Schedule "E"	-	Electric Service for Employees
Schedule "G"	-	General Service - Non Demand
Schedule "J"	-	*General Service Demand*
Schedule "H"	-	Commercial Cooking and Heating Service
Schedule "P"	-	Large Power Service
Schedule "F"	-	Street Lighting Service
Schedule "U"	-	Time-of-Use Service
Schedule "TOU-R"	-	Residential Time-of-Use Service
Schedule "TOU-G"	-	Small Commercial Time-of-Use Service
Schedule "TOU-J"	-	Medium Commercial Time-of-Use Service
Schedule "TOU-P"	-	Large Power Time-of-Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "P", "F", "U", "TOU-R", "TOU-G", "TOU-J" and "TOU-P" are applicable, except that the Energy Cost Adjustment Clause described below will be added to the customer bills.

All base rate schedule discounts, surcharges, and all other adjustments will not apply to the energy cost adjustment.

Energy Cost Adjustment Clause:

This Energy Cost Adjustment Clause shall include the following:

FUEL AND PURCHASED ENERGY - The above rates are based on a company-owned central station and wind/hydro generation cost (exclusive of company-owned distributed generation (DG)) of 1,064.43 cents per million BTU for fuel delivered in its service tanks, a purchased energy composite cost of 13.631 cents per kilowatthour, and a company-owned DG energy composite cost of 14.942 cents per kilowatthour for fuel delivered to the fuel tank at the site used for company-owned DG. Company-generated energy from non-fuel sources shall be considered as zero fuel cost in the determination of the composite fuel cost.

When the Company-generated Composite Cost of Generation is more or less than 1,064.43 cents per million BTU, and/or the Purchased Energy Cost is more or less than 13.631 cents per kilowatthour, and/or the company-owned DG Energy Composite Cost is more or less *than 14.942 cents per kilowatthour, a corresponding adjustment* (Energy Cost Adjustment Factor) to the energy charges shall be made.

Superseding Revised Sheet No. 63A
Effective February 15, 2001

Revised Sheet NO. 63A
Effective

Energy Cost Adjustment Clause - Continued

This adjustment shall be comprised of a Company Composite Central Station With Wind/Hydro Generation Component, a Purchased Energy Component, and a DG Energy Generation Component.

The Company Composite Central Station With Wind/Hydro Generation Component shall be the difference between the current Weighted Composite Central Station + Wind/Hydro Generation Cost and the Weighted Base Central Station + Wind/Hydro Generation Cost, adjusted for additional revenue taxes. The current Weighted Composite Central Station + Wind/Hydro Generation Cost shall be determined by the current Composite Cost of Generation in cents per million BTU weighted by the proportion of current company-owned central station + wind/hydro generation to total system net energy, multiplied by the 2006 test-year efficiency factors of 0.015615 million BTU per kilowatthour for industrial fuel, 0.013526 million BTU per kilowatthour for diesel fuel, and 0.014826 million BTU per kilowatthour for other company generation sources, weighted by the current proportion of generation produced by each generation source to the total company-owned generation.

The Weighted Base Central Station + Wind/Hydro Generation Cost is the Base Central Station + Wind/Hydro Generation Cost of 1,064.43 cents per million BTU weighted by the 2006 Test Year proportion of company-owned central station + wind/hydro generation to total system net energy, multiplied by the 2006 Test year efficiency factor of 0.014826 million BTU per kilowatthour.

The Purchased Energy Component shall be the difference between (1) the current Composite Cost of Purchased Energy weighted by the proportion of current purchased energy to the total system net energy, and (2) the Base Purchased Energy Composite Cost of 13.631 cents per kilowatthour weighted by the 2006 Test Year proportion of the purchased energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes.

The Distributed Generation Energy Component shall be the difference between (1) the current Composite Cost of DG Energy weighted by the proportion of current DG energy to total system net energy, and (2) the Base DG Energy Composite Cost of 14.942 cents per kilowatthour weighted by the proportion of the 2006 Test Year DG energy to total system net energy, adjusted to the sales delivery level and for additional revenue taxes.

The Energy Cost Adjustment Factor shall be the sum of the Central Station With Wind/Hydro Generation Component, the Purchased Energy Component and the DG Energy Generation Component.

Energy Cost Adjustment Clause - Continued

The revenue tax requirement shall be calculated using current rates of the Franchise Tax, Public Service Company Tax, and Public Utility Commission Fee.

The Adjustment shall be effective on the date of cost change. When a cost change occurs during a customer's billing period, the Adjustment will be prorated for the number of days each cost was in effect.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations, purchased energy contracts, and DG contracts, and may be revised to reflect any revisions or changes in operations, purchased energy contracts, and is subject to approval by the Commission.

Reconciliation Adjustment:

In order to reconcile any differences that may occur between recorded and forecasted Energy Cost Adjustment Clause revenues, the year-to-date recorded revenue from the Energy Cost Adjustment Clause will be compared with the year-to-date revenue expected from the Energy Cost Adjustment Clause on a quarterly basis. If there is a variance between the recorded Energy Cost Adjustment Clause revenue and the expected Energy Cost Adjustment Clause revenue, an adjustment, lagged by two months, shall be made to the Energy Cost Adjustment Clause to reconcile the revenue variance over the sales estimated for the subsequent quarter.

Superseding Revised Sheet No. 64
Effective April 1, 2006

REVISED SHEET NO. 64
Effective

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION

Applicable To

Schedule "R"	-	Residential Service
Schedule "E"	-	Electric Service for Employees
Schedule "G"	-	General Service Non-Demand
Schedule "J"	-	General Service Demand
Schedule "H"	-	Commercial Cooking and Heating Service
Schedule "P"	-	Large Power Service
Schedule "F"	-	Street Lighting Service
Schedule "U"	-	Time-of-Use Service
Schedule "TOU-R"	-	Residential Time-of-Use Service
Schedule "TOU-G"	-	Small Commercial Time-of-Use Service
Schedule "TOU-J"	-	Commercial Time-of-Use Service
Schedule "TOU-P"	-	Large Power Time-of-Use Service

All terms and provisions of Schedules "R", "E", "G", "J", "H", "P", "F", "U", "TOU-R", "TOU-G", "TOU-J" and "TOU-P" are applicable, except that the total base rate charges for each billing period shall be increased by the following Integrated Resource Planning (IRP) Cost Recovery Adjustment, Residential Demand-Side Management (DSM) Adjustment, Commercial and Industrial Demand-Side Management (DSM) Adjustment, and Renewable Energy Programs (REP) Adjustment:

A. INTEGRATED RESOURCE PLANNING COST RECOVERY ADJUSTMENT:

All Rate Schedules........................ 0.000 percent

The total base rate charges for all rate schedules shall be decreased by the above Integrated Resource Planning Cost Recovery Adjustment, which is based on the reconciliation of the recovery of the _____ IRP Planning Costs, including interest and taxes, as approved by the Public Utilities Commission.

The total base rate charges for the current billing period shall include all base rate schedule charges, discounts, surcharges, or base rate adjustments, excluding the Energy Cost Adjustment, Firm Capacity Surcharge, Firm Capacity Surcharge Adjustment, Residential DSM Adjustment, Commercial and Industrial DSM Adjustment and Renewable Energy Programs Adjustment.

Superseding Revised Sheet No. 65
Effective April 1, 2006

REVISED SHEET NO. 65
Effective

Integrated Resource Planning Cost Recovery Provision - Continued

B. Residential Demand-Side Management (DSM) Adjustment

Schedule R and TOU-R - per kWhr............... __ ¢/kWh

The total residential monthly bill shall include the above Residential DSM adjustment applied to all kWh per month. The above Residential DSM adjustment is based on recovering $________ for the 2006 residential program costs, lost revenue margins and revenue taxes, the 2005 shareholder incentives, and the reconciliation of the 2005 program costs recovery including lost revenue margins and revenue taxes for which recovery has been approved by the Public Utilities Commission.

C. Commercial and Industrial Demand-Side Management (DSM) Adjustment:

Schedules G, J, H, P, U, TOU-G, TOU-J, TOU-P - per kWhr __ ¢/kWh

The total monthly bill for Schedules G, J, H, P, U, TOU-G, TOU-J, and TOU-P customers shall include the above Commercial and Industrial DSM adjustment applied to all kWh per month. The above adjustment is based on recovering $________ for the 2006 C&I program costs, lost revenue margins and revenue taxes, the 2005 shareholder incentives, and the reconciliation of the 2005 program cost recovery including lost revenue margins and revenue taxes, for which recovery has been approved by the Public Utilities Commission.

D. Renewable Energy Programs Adjustment:

All Rate Schedules............................. __ ¢/kWh

The total base rate charges for all rate schedules shall be increased by the above Renewable Energy Programs Adjustment, which is based on the recovery of ___for the Renewable Energy Programs, including interest and taxes, as approved by the Public Utilities Commission.

Integrated Resource Planning Cost Recovery Provision - Continued

RECONCILIATION ADJUSTMENT: (To be added to Integrated Resource Planning Cost Recovery Adjustment, Residential DSM Adjustment, Commercial and Industrial DSM Adjustment, Renewable Energy Programs Adjustment):

In order to reconcile any differences that may occur between the above costs to be recovered and the revenues received from the above adjustments, recorded revenues will be compared with the above costs. The Integrated Resource Planning Cost Recovery, Residential DSM Adjustment, the Commercial and Industrial DSM Adjustment and the Renewable Energy Programs Adjustment will be reconciled annually. If there is a variance between the recorded revenues from the adjustments and the costs to be recovered, a reconciliation adjustment, lagged by two months, will be made to the above adjustments.

Superseding Sheet No. 70
Effective June 5, 2001

REVISED SHEET NO. 70
Effective

RIDER A

STANDBY SERVICE

APPLICABILITY:

Applicable to standby service to customers with alternate regular source(s) of electric power other than the Company (non-utility power source(s)). Service under this Rider shall be at least 25 kW, supplied and metered at a single voltage and delivery point as specified by the Company.

Standby service is the power service that the Company is obligated to stand ready to supply when the customer's non-utility power source(s) is unavailable for service. Standby service refers to Scheduled Maintenance Service or Backup Service, or both.

Scheduled Maintenance Service is the standby service supplied by the Company during the Scheduled Maintenance Period(s) for the customer's non-utility power source(s) as specified in the Standby Service Contract.

Backup Service is the standby service supplied by the Company when the customer's non-utility power source(s) is unavailable due to unscheduled outages.

Supplemental Service is the power service supplied by the Company in addition to the customer's electric power requirements normally obtained from its non-utility power source(s). The Company will serve the customer's supplemental service under Schedule J or Schedule P, whichever is applicable.

DETERMINATION OF DEMAND:

Standby Demand:

The Standby Billing kW for each month shall be the customer's Contract Standby kW as specified in the Standby Service Contract.

Superseding Sheet No. 70A
Effective June 5, 2001

REVISED SHEET NO. 70A
Effective

RIDER A - Continued

Supplemental Demand:

The Demand Charge of the applicable rate schedule shall apply to the customer's Supplemental Billing kW.

For Schedule J customers, the Supplemental Billing kW for each month shall be the difference between the Total kW Load for such month, or the mean of the current month's Total kW Load and highest Total kW Load for the previous eleven months, whichever is higher, less the Standby Billing kW, but not less than 25 kW.

For Schedule P customers, the Supplemental Billing kW for each month shall be the difference between the Total kW Load for such month, or the mean of the current month's Total kW Load and highest Total kW Load for the previous eleven months, whichever is higher, less the Standby Billing kW, but not less than 200 kW.

If the customer qualifies to elect and does elect to limit its Contract Standby kW to the sum of the capacities of its two largest non-utility power sources, then the customer's Supplemental Billing kW shall be determined by subtracting (instead of subtracting the Standby Billing kW) the lesser of:

(a) the Total Capacity of the customer's non-utility power sources, normally connected and operating in parallel with the Company's system, or

(b) the maximum measured kW load supplied by such non-utility power sources.

The customer's Total kW Load for each month shall be the maximum time-coincident sum of the measured kW load supplied by the Company and the measured kW load supplied by the customer's non-utility power source(s). The maximum time-coincident measured kW load for each month shall be the maximum time-coincident average load in kW during any fifteen minute period.

RATES:

The rates, terms, and conditions of Schedule J or Schedule P, whichever is applicable, shall apply except that the following Standby Demand Charge, Scheduled Maintenance Service Energy Charge, and Excess Standby Demand Charge shall be added to the customer's bill, and the Minimum Charge and Determination of Demand provisions of this Rider shall supersede the Minimum Charge and Determination of Demand provisions in the applicable standard rate schedule:

Superseding Sheet No. 70B
Effective June 5, 2001

REVISED SHEET NO. 70B
Effective

RIDER A - Continued

Standby Demand Charge:

Schedule J: All kW of standby billing demand (Standby Billing kW) - per kW $12.10

Schedule P: All kW of standby billing demand (Standby Billing kW) - per kW $13.10

Scheduled Maintenance Service Standby Demand Charge Discount

The Standby Demand Charge will be reduced by 10% for customers who elect and qualify for Scheduled Maintenance Service, provided that such reduction in the Standby Demand Charge shall only apply in each month in which the customer's non-utility power source(s) had no outages or partial outages other than scheduled outages during Scheduled Maintenance Periods. A "partial" outage would occur when a customer's non-utility power source was operated at a capacity of 70% or lower than its nameplate rating (during a period when the customer was receiving supplemental energy from the Company).

Scheduled Maintenance Service Energy Charge:

Schedule J: All maintenance kWh during Scheduled maintenance period will be charged at 16.9 ¢/kWh.

Schedule P: All maintenance kWh during Scheduled maintenance period will be charged at 16.1 ¢/kWh.

The energy charge for scheduled maintenance service shall apply to the kWh used by the customer as a result of the scheduled maintenance of the customer's non-utility power source(s) during the Scheduled Maintenance Period(s) when the customer's non-utility power source(s) is actually down for maintenance. Such kWh will be based on the lesser of:

(a) the Scheduled Maintenance kW load specified in the Standby Service Contract for the customer's non-utility power source(s) that is actually down for scheduled maintenance, multiplied by the number of hours when such non-utility power source(s) is down for maintenance as indicated by the meter on such source(s), or

Superseding Sheet No. 70C
Effective June 5, 2001

REVISED SHEET NO. 70C
Effective

RIDER A - Continued

(b) the measured kwh supplied by the Company during the Scheduled Maintenance Period when the customer's non-utility power source(s) is actually down for maintenance.

Backup Service Energy Charge:

The charge for energy taken under Backup Service shall be the energy rates applicable for supplemental service, which are the energy rates under Schedule J or Schedule P.

Excess Standby Demand Charge:

A customer with at least three non-utility power sources, with each such source separately metered, may elect to limit its Contract Standby kW to the sum of the capacity of its two largest power sources, subject to the Terms and Conditions of this Rider. If a customer makes this election and its standby service requirements during a month exceed its Contract Standby kW, then the excess standby service demand (i.e., the difference between the customer's maximum Standby Service Requirement and the Contract Standby kW) shall be billed at the following Excess Standby Demand Charge.

Excess Standby Demand Charge - per Excess Standby kW $30.00

The customer's standby service requirement for each fifteen minute period shall be the lesser of:

(a) the Total Capacity of the customer's non-utility power source(s) connected and operating in parallel with the Company's system less the measured kW supplied by such sources during each fifteen minute period, or

(b) the measured kW supplied by the Company during the same fifteen minute period plus the Standby Contract kW.

The Customer's Excess Standby kW for the month shall be the difference between the customer's maximum Standby Service Requirement for any fifteen minute period during the month, less the customer's Contract Standby kW.

Superseding Sheet No. 70D
Effective June 5, 2001

REVISED SHEET NO. 70D
Effective

RIDER A - Continued

The Excess Standby kW will be added to the customer's Contract Standby kW to reset a new Contract Standby kW in each succeeding billing month.

Supply Voltage Adjustment:

The Supply Voltage Adjustment in the applicable standard rate schedule shall apply to the Standby Demand Charge (after application of the Scheduled Maintenance Service Standby Demand Charge Discount, if any), the Excess Standby Demand Charge, and the Scheduled Maintenance Service Energy Charge.

MINIMUM CHARGE:

The monthly minimum charge shall be the sum of the Minimum Charge under the applicable rate schedule, the Standby Demand Charge and Excess Standby Demand Charge. Where the Company determines that the installed capacity of the customer's non-utility power source(s) exceeds the customer's total kW requirement as determined by the Company, the monthly minimum charge shall be the sum of the Customer Charge under the applicable rate schedule, the Standby Demand Charge, and the Excess Standby Demand Charge.

For Schedule J customers, the kW used in the Minimum Charge calculation shall be the Total kW Load for the month, or the greatest Total kW Load for the preceding eleven months, whichever is higher, less the Standby Billing kW, but not less than 25 kW.

For Schedule P customers, the kW used in the Minimum Charge calculation shall be the Total kW Load for the month, or the greatest Total kW Load for the preceding eleven months, whichever is higher, less the Standby Billing kW, but not less than 200 kW.

If the customer qualifies to elect and does elect to limit its Contract Standby kW to the sum of the capacities of its two largest non-utility power sources, then the kW used in the Minimum Charge calculation shall be determined by subtracting (instead of subtracting the Standby Billing kW) the lesser of:

(a) the Total Capacity of the customer's non-utility power sources, normally connected and operating in parallel with the Company's system, or

(b) the maximum measured kW load supplied by such non-utility power sources.

Superseding Sheet No. 70E
Effective June 5, 2001

REVISED SHEET NO. 70E
Effective

RIDER A - Continued

TERMS AND CONDITIONS:

1. This Rider shall apply when a customer regularly obtains power service from a source(s) other than the Company, and obtains supplemental service from the Company when its non-utility power source(s) capability is less than its total power requirements; and/or requires standby service from the Company.

2. This Rider shall not apply when a customer's non-utility power source(s) is used exclusively for emergency service in case of failure of the normal supply of power service from the Company, or to a customer that has an Agreement with the Company which provides for the sale of electric energy and/or capacity to the Company that was approved by the Commission prior to October 25, 1999, or to a customer whose non-utility power is produced from a non-fossil energy source.

3. The connection and operation of the customer's non-utility power source(s) in parallel with the Company's system will be permitted when the customer is served under this Rider, and in accordance with the terms of a contract with the Company for parallel interconnection.

4. Customers receiving service under this Rider shall sign a Standby Service Contract with the Company, which shall specify the Contract Standby kW for standby service required from the Company, and the Scheduled Maintenance Service, if any, elected by the customer.

5. The Contract Standby kW initially will be based on the Total Capacity of the customer's non-utility power source(s) (except as provided below), or will be jointly determined by the Company and the customer.

   The Total Capacity of the customer's non-utility power source(s) will be determined by, but not limited to, such indicators as the nameplate rating(s) of the generating unit(s), and the design specifications and operating characteristics of the generating unit(s).

Superseding Sheet No. 70F
Effective June 5, 2001

REVISED SHEET NO. 70F
Effective

RIDER A - Continued

TERMS AND CONDITIONS - Continued

The Contract Standby kW, when jointly determined by the Company and the customer, must be determined by the Company to be reasonable given the Total Capacity of the customer's non-utility power sources, which are connected and operated in parallel with the Company's system, the extent to which the capacity of the customer's service connection is limited, and such other information as the Company considers pertinent to the determination of the appropriate Contract Standby kW requirements of the customer.

The Contract Standby kW normally will not be less than the lesser of (a) the Total Capacity of the customer's non-utility power source(s) (except as provided below), or (b) the greatest Total kW Load for the twelve months preceding commencement of service under this rider, or execution of the Standby Service Contract, whichever is earlier.

In the event that the maximum measured kW load supplied by the customer's non-utility power source(s) exceeds the Contract Standby kW (except as provided below), then the Contract Standby kW shall be automatically adjusted to an amount equal to the maximum measured kW load beginning with the month in which the maximum measured kW load occurred. Each such automatically adjusted Contract Standby kW shall be in effect thereafter for such customer, unless superceded by another automatically adjusted Contract Standby kW.

A customer with at least three non-utility power sources, with each such source separately metered, may elect to limit its Contract Standby kW to the sum of the capacities of its two largest non-utility power sources. If such a customer incurs Excess Standby kW, such Excess Standby kW will be added to the customer's Contract Standby kW to reset a new Contract Standby kW in each succeeding billing month.

A customer electing to limit its Contract Standby kW to the sum of the capacities of its two largest power sources shall also elect Scheduled Maintenance Service for its non-utility power sources, and shall take scheduled maintenance for only one of its non-utility power sources at a time.

Superseding Sheet No. 70G
Effective June 5, 2001

REVISED SHEET NO. 70G
Effective

RIDER A - Continued

TERMS AND CONDITIONS - Continued

6. The customer must notify the Company of any changes in its non-utility power source(s) that may affect its Contract Standby kW specified in the Standby Service Contract. The Company may, from time to time, verify the customer's Contract Standby kW specified in the Standby Service Contract. Where the Company determines that the Contract Standby kW requires adjustment, the Company shall inform the customer in writing 60 days before such change becomes effective.

7. The maximum instantaneous demand may be limited by contract. When the capacity of the service connection is limited to conform with the Contract Standby kW, the customer shall provide, install and maintain at its expense, and the Company shall control, any circuit breaker and other equipment necessary to limit the service connection to the Contract Standby kW.

8. The Company shall not be liable for any consequential damages caused by, or resulting from any limitation of kW capacity supplied to the customer under this Rider.

9. Scheduled Maintenance Service under this rate Schedule shall be for power service during the Scheduled Maintenance Period of the customer's non-utility power source(s). A customer electing to take Scheduled Maintenance Service shall specify in the Standby Service Contract whether it is taking Standard Scheduled Maintenance Service, or Off-peak Scheduled Maintenance Service (if it is eligible for such option).

   For Standard Scheduled Maintenance Service, maintenance for a customer's non-utility power source must be scheduled no more than two times per year, for a total period not to exceed three weeks, and is subject to the following terms and conditions:

   a. The Scheduled Maintenance Periods shall not exceed a total of 3 weeks per non-utility power source within a calendar year. A non-utility power source cannot be down for maintenance more than 2 times during the calendar year.

Superseding Sheet No. 70H
Effective June 5, 2001

REVISED SHEET NO. 70H
Effective

RIDER A - Continued

TERMS AND CONDITIONS - Continued

b. The customer shall specify its initial Scheduled Maintenance Periods (to be taken during the first calendar year or partial calendar year in which it takes Standard Scheduled Maintenance Service), subject to review and approval by the Company, in the Standby Service Contract. Prior to _____ of each year, the customer shall submit in writing to the Company any changes to the Scheduled Maintenance Periods for the following calendar year. Where the Company indicates within 60 days that any such changes are not acceptable to the Company based on operating, technical or other similar reasons, the Company and the customer will work together to determine the changes to the Scheduled Maintenance Periods that are reasonable and acceptable to both parties.

c. Either HELCO or the customer may request one change in the start date and/or duration of any scheduled outage by written request (specifying the reason for such request, and the proposed start date and/or duration of the scheduled outage) made at least thirty days before the scheduled start of such outage. HELCO and the customer will make reasonable efforts to accommodate such requests (by written responses given within one week of receiving such requests).

A customer with one or more non-utility power source(s) with capabilities of less than or equal to 500 kW, may elect Off-peak Scheduled Maintenance Service where the Scheduled Maintenance Periods occur only during the Company's off-peak period, subject to the following conditions:

a. A power source (or power sources up to a maximum capability of 500 kW) can be maintained during off-peak hours with one-week prior notice to HELCO. Notice can be given either by phone, fax, or e-mail, and must include the meter number for the power source(s) to be maintained and the expected additional kW demand to be provided by the Company during the Scheduled Maintenance Service period(s). Off-peak hours are 9 p.m. - 7 a.m., daily.

Superseding Sheet No. 70I
Effective June 5, 2001

REVISED SHEET NO. 70I
Effective

RIDER A - Continued

TERMS AND CONDITIONS - Continued

b. Maintenance on the same power source can be scheduled no more than twice within a four-week period. The customer must call the Company in advance of shutting off and/or starting up its power source that will be maintained under this provision.

c. The Standby Service Contract must specify the non-utility power source(s) and meter numbers of the sources to be maintained during off-peak hours under the above terms. Such power sources are not eligible for Standard Scheduled Maintenance Service.

10. The customer's non-utility power source(s) shall be metered, unless the Company deems such metering to be impractical for engineering or operating reasons. If the customer's non-utility power source(s) cannot be metered by the Company, then the customer's Total kW Load for each month shall be the sum of the maximum measured kW load supplied by the Company and the Contract Standby kW, and the customer shall not be eligible for Scheduled Maintenance Service. If the customer has more than one non-utility power source, and elects scheduled maintenance service for only one of its non-utility power sources at a time, then each of the customer's non-utility power sources shall be separately metered.

11. The Company shall install, own, operate, maintain, and read meters on the customers non-utility power source(s) for billing purposes. The customer shall be responsible for any cost associated with metering its non-utility power source(s), including the total installed cost of the meters. All meters shall be installed at some convenient place approved by the Company upon the customer's premises, and shall be so placed as to be accessible at all times for inspection, reading, and testing.

Superseding Sheet No. 70J
Effective June 5, 2001

REVISED SHEET NO. 70J
Effective

RIDER A - Continued

TERMS AND CONDITIONS - Continued

When the Company performs maintenance work on the meters on the customer's non-utility power source(s), the Company shall bill the customer for the total cost associated with such maintenance including labor and material costs, and shall add this amount to the customer's electric bill for the period. The Company shall provide the customer with the breakdown of such maintenance costs such as the labor cost, materials and supplies, taxes, and any other cost incurred.

The customer shall, at its expense, furnish, install and maintain in accordance with the Company's requirements all associated equipment such as all conductors, service switches, fuses, meter sockets, meter and instrument transformer housing and mountings, switchboard meter test buses, meter panels, and similar devices, required for service connection and meter installations on customer's premises.

The customer shall at its expense, provide a dedicated telephone line to connect the meter(s) to the Company's communication system.

The meter(s) shall be ratcheted to prevent reversal or reverse registration.

12. The term of contract under this Rider is at least one (1) year, and the contract shall remain in effect from month-to-month thereafter, unless terminated by either party upon thirty (30) days prior written notice to the other party.

13. Service supplied under this Rider shall be subject to the Rules and Regulations of the Company.

Superseding Sheet No. 70K
Effective June 5, 2001

REVISED SHEET NO. 70K
Effective

RIDER A CONTRACT FORM
Standby Service

This Contract covers Standby Service provided by HAWAII ELECTRIC LIGHT COMPANY, INC. (HELCO) to:

Customer: ____________________ Account Number: ______________________

Service Address: ____

Under this Contract, the electric service provided by HELCO to the customer's service location shall be served on rate Schedule _____ and Rider A. All terms of Schedule _____ shall apply, except as further specified in Rider A and in this Contract.

The standby service under Rider A shall be: (check one)

__________ Backup Service ____________ Scheduled Maintenance Service

If customer elects Scheduled Maintenance Service: (check one)

_______ Standard Scheduled Maintenance Service
_______ Off-peak Scheduled Maintenance Service

Contract Standby kW ________ (1)
Installed kW Capacity of Each Non-Utility Power Source ______ (2)
Total Number of Non-Utility Power Sources _____ (3)
Scheduled Maintenance Periods & Non-Utility Power Sources to be maintained: ____
____
____

This Contract shall become effective at the beginning of the first regular billing cycle following _______________(date) or the first billing period after the installation of the required meters for service under Schedule _____ and Rider A, whichever occurs later.

The parallel interconnection of the customer's non-utility power sources with the Company's system shall be permitted in accordance with the terms and conditions specified in a contract for parallel interconnection.

Term of Contract shall be at least one year, and shall continue thereafter month-to-month until terminated by either party upon thirty (30) days prior written notice to the other party. This Contract may be terminated at any time by mutual agreement of the Company and the customer.

Authorized Customer Signature: HELCO Representative:

Name	Date	Name	Date
Title		Title	
Company			

SHEET NO. 71
Effective

SCHEDULE TOU-R

RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to residential service metered and billed separately by the Company. This Schedule does not apply where a residence and business are combined. Service under this Schedule will be delivered at secondary voltages as specified by the Company.

Service under this Schedule shall be limited to a total of 300 meters.

RATES:

CUSTOMER CHARGE - $ per customer per month:

Single-Phase Service	- per month	$11.00/month
Three-Phase Service	- per month	$15.50/month

ENERGY CHARGES - ¢ per kWh:

<u>Base Charges</u>

First 300 kWh per month - per kWhr	29.2699 ¢/kWhr
Next 700 kWh per month - per kWhr	31.3804 ¢/kWhr
All kWh over 1,000 kWh per month - per kWhr	32.2111 ¢/kWhr

<u>Time-of-Use Charges</u>

Priority Peak Period	- per kWhr	5.0 ¢/kWhr
Mid-Peak Period	- per kWhr	2.5 ¢/kWhr
Off-Peak Period	- per kWhr	- 5.0 ¢/kWhr

SHEET NO. 71A
Effective

SCHEDULE TOU-R - (continued)

MINIMUM CHARGE:

The minimum charge shall be the higher of $20.00 or the bill calculated at base rates plus current rate adjustments using 15% of the customer's highest billed kWh over the previous 11 billing months.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

Priority Peak:	5:00 p.m.-9:00 p.m., Monday-Friday
Mid-Peak:	7:00 a.m.-5:00 p.m., Monday-Friday 7:00 a.m.-9:00 p.m., Saturday-Sunday
Off-Peak:	9:00 p.m.-7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 71B
Effective

Schedule TOU-R - (continued)

TERMS AND CONDITIONS - continued:

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule R at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

ENERGY COST ADJUSTMENT CLAUSE:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer and Energy Charges.

INTEGRATED RESOURCE PLANNING COST RECOVERY PROVISION:

The Integrated Resource Planning Surcharge shall be added to the Customer and Energy Charges, and energy cost adjustment.

RULES AND REGULATIONS:

Service supplied under this rate schedule shall be subject to the Rules and Regulations of the Company.

SHEET NO. 72
Effective

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5,000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts will be automatically transferred to Schedule TOU-J at the beginning of the next billing period.

Service will be delivered at secondary voltages as specified by the Company, except where the nature or location of the customer's load makes delivery at secondary voltage impractical, the Company may, at its option, deliver the service at a nominal primary voltage as specified by the Company.

Service under this Schedule shall be limited to a total of 100 meters.

RATE:

CUSTOMER CHARGE:

Single-Phase Service - per month	\$39.00/month
Three-Phase Service - per month	\$61.00/month

ENERGY CHARGE: (To be added to Customer and Demand Charge)

Priority Peak Period	- per kWhr	37.2535 ¢/kWhr
Mid-Peak Period	- per kWhr	34.7535 ¢/kWhr
Off-Peak Period	- per kWhr	27.2535 ¢/kWhr

MINIMUM CHARGE: Customer Charge

SCHEDULE TOU-G - continued

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY:

The Company shall install, own, operate and maintain a time-of-use meter to measure the customer's kWh energy consumption during the time-of-use rating periods.

TERMS AND CONDITIONS:

1) The Company may meter the customer's energy usage pattern for one to two months before the customer's service start date under this Schedule, to allow the Company to gather the customer's baseline load profile.

2) The Company shall install the time-of-use meter in accordance with Rule 14. Although the existing service equipment is expected to be used, the customer shall provide, install, and maintain the service equipment specified in Rule 14, such as all the conductors, service switches, meter socket, meter panel, and other similar devices required for service connection and meter installations on the customer's premises.

SHEET NO. 72B
Effective

SCHEDULE TOU-G - continued

TERMS AND CONDITIONS - continued:

3) The Company may request a customer to allow the Company shared-use of its telephone line to enable the Company to remotely download the customer's usage data from the meter.

4) A customer may terminate service under this rate Schedule and return to the regular Schedule G at any time without penalty, by a written notice to the Company. The change shall become effective at the start of the next regular billing period following the date of receipt by the Company of the notice from the customer. If a customer elects to discontinue service under this Schedule, the customer will not be permitted to return to this Schedule for a period of one year.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 73
Effective

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month three times within a twelve-month period or which exceed 25 kW per month and but are less than 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, Schedule U, and Schedule TOU-P.

Service under this Schedule shall be limited to a total of 50 meters.

RATE:

CUSTOMER CHARGE:

Single-Phase Service	- per month	$49.00/month
Three-Phase Service	- per month	$75.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$19.25/kW
Mid-Peak	- per kW of billing demand	$12.00/kW.

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	32.2063 ¢/kWhr
Mid-Peak Period	- per kWhr	30.2063 ¢/kWhr
Off-Peak Period	- per kWhr	20.2063 ¢/kWhr

SHEET NO. 73A
Effective

SCHEDULE TOU-J - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 25 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 25 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.10%.

SHEET NO. 73B
Effective

SCHEDULE TOU-J - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.0%
Distribution voltage supplied without further transformation	-2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

SHEET NO. 74
Effective

SCHEDULE TOU-P

LARGE POWER TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to large light and/or power service supplied and metered at a single voltage and delivery point. Loads must exceed 200 kW per month. This Schedule cannot be used in conjunction with load management Riders M, T, and I, and Schedule TOU-P.

Service under this Schedule shall be limited to a total of 12 meters.

RATE:

CUSTOMER CHARGE: $510.00 per month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	- per kW of billing demand	$24.50/kW
Mid-Peak	- per kW of billing demand	$19.50/kW

The customer shall be billed the Priority Peak demand charge if his maximum measured kW demand for the billing period occurs during the priority peak period. If the customer's maximum measured kW demand for the billing period occurs during the Mid-Peak period, the Mid-Peak demand charge will apply. If the customer's maximum kW demand during the Priority Peak period is equal to his maximum kW demand during the Mid-Peak period, the Priority Peak demand charge shall apply.

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	- per kWhr	29.5793 ¢/kWhr
Mid-Peak Period	- per kWhr	27.5793 ¢/kWhr
Off-Peak Period	- per kWhr	17.5793 ¢/kWhr

SCHEDULE TOU-P - (continued)

MINIMUM CHARGE:

The minimum charge per month shall be the sum of the Customer Charge and the Demand Charge. The Demand Charge shall be computed with the above demand charge applied to kilowatts of demand. The kilowatts of demand for the minimum charge calculation each month shall not be less than 200 kW.

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods shall be as follows:

Priority Peak:	5:00 a.m. - 9:00 p.m., Monday - Friday
Mid-Peak:	7:00 a.m. - 5:00 p.m., Monday - Friday
	7:00 a.m. - 9:00 p.m., Saturday - Sunday
Off-Peak:	9:00 p.m. - 7:00 a.m., Daily

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption and kilowatt load during the time-of-use rating periods. The maximum demand for the rating periods for each month shall be the maximum average load in kilowatts during any fifteen-minute period as indicated by a time-of-use meter. The kilowatts of billing demand for each month shall be the maximum measured demand outside of the Off-Peak hours, but not less than 200 kW.

Power Factor:

The above energy and demand charges are based upon an average monthly power factor of 85%. For each 1% the average power factor is above or below 85%, the monthly energy and demand charges as computed under the above rates shall be decreased or increased, respectively, by 0.15%.

SCHEDULE TOU-P - (continued)

Power Factor - continued:

The average monthly power factor will be determined from the readings of a kWhr meter and kvarh meter, and will be computed to the nearest whole percent and not exceeding 100% for the purpose of computing the adjustment. The kvarh meter shall be ratcheted to prevent reversal in the event the power factor is leading at any time.

Supply Voltage Delivery:

If the customer takes delivery at the Company's supply line voltage, the demand and energy charges will be decreased as follows:

Transmission voltage supplied without further transformation	-4.0%
Distribution voltage supplied without further transformation	-2.5%

Metering will normally be at the delivery voltage. When the customer's transformers are adjacent to the delivery point, the customer may elect to be metered at a single point on the secondary side of his transformers where such point is approved by the Company. When the energy is metered on the secondary side of the customer's transformers, the above decreases will be 3.1% and 0.6%, respectively.

Energy Cost Adjustment Clause:

The energy cost adjustment provided in the Energy Cost Adjustment Clause shall be added to the Customer, Demand, and Energy charges.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, and energy cost adjustment.

Rules and Regulations:

Service supplied under this rate shall be subject to the Rules and Regulations of the Company.

Superseding Revised Sheet No. 81
Effective February 15, 2001

REVISED SHEET NO. 81
Effective

SCHEDULE "Q"

Purchases From Qualifying Facilities - 100 KW or Less

Availability:

This schedule is available to customers with cogeneration and/or small power production facilities which qualify under the Commission's Rules, Chapter 74 of Title 6, Subchapter 2 with a design capacity of 100 kilowatts or less. Such qualifying facilities (QF's) shall be designed to operate properly in parallel with the Company's system without adversely affecting the operations of its customers and without presenting safety hazards to the Company's or other customer's personnel. The customer shall comply with the Company's requirements for customer generation interconnected with the utility system.

Energy delivered to the customer by the Company will be metered separately from the energy delivered by the customer to the Company.

Rate for Energy Delivered to the Company by Customer

The Company will pay for energy as follows:

All kWhr per month - per kWhr	15.830 ¢

Metering Charge:

There is a monthly charge to the customer for metering, billing and administration of the interconnection for purchase power as follows:

Single phase service - per month	$5.00
Three phase service - per month	$10.00

Energy Delivered to the Customer by the Company:

Energy delivered to the customer shall be billed on an applicable Company rate schedule.

System Compatibility:

The customer must deliver electric power at 60 hertz and the same phase and voltage as the customer receives service from the Company.

Superseding Revised Sheet No. 81A
Effective February 15, 2001

REVISED SHEET NO. 81A
Effective

Schedule "Q" (Continued)

Interconnection Facilities:

The customer shall furnish, install, operate and maintain facilities such as relays, switches, synchronizing equipment, monitoring equipment and control and protective devices designated by the Company as suitable for parallel operation with the Company system. Such facilities shall be accessible at all times to authorized Company personnel. All designs should be approved by the Company prior to installation.

If additional Company facilities are required or the existing facilities must be modified to accept the QF's deliveries, the QF shall make a contribution for the cost of such additional facilities.

Contract:

The Company shall require a contract specifying technical and operating aspects of parallel generation.

Energy Cost Adjustment Clause:

The above rate for energy delivered to the Company by the Customer is based on a composite cost of central station and DG for Company generation of 1064.54 per million Btu for fuel delivered in its service tanks. Effective the first day of January, April, July, and October an Adjustment shall be made to reflect the Company-generated fuel cost on file with the Commission and shall be effective for the following three months.

The Adjustment shall be the sum of the time-weighted on-peak adjustment (14 hours of 24 hours) and off-peak adjustment (10 hours of 24 hours). On-peak and off-peak adjustments shall be determined by the amount of the Company-generated fuel cost increase or decrease (in terms of cents per million Btu) from the base of 1064.54¢ per million Btu multiplied by an on-peak heat rate of 16,002 Btu per net kilowatthour and an off-peak heat rate of 12,763 Btu per net kilowatthour.

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations and may be revised to reflect any revisions or changes in operations, subject to approval by the Commission.

Superseding Revised Sheet No. 82
Effective January 1, 1999

REVISED SHEET NO. 82
Effective

GREEN PRICING PROGRAM PROVISION

AVAILABILITY:

Available to all residents/non-residents of the Big Island, Hawaii who wish to make voluntary contributions for the development of renewable energy resources on Big Island, Hawaii.

GREEN PRICING PROGRAM:

The objective of the Green Pricing Program is to encourage the development of Hawaii's renewable energy resources. The participant's voluntary contributions under the Green Pricing Program Provision are used to develop renewable energy facilities.

The Company's Sun Power for Schools Pilot Program is a pilot project under which photovoltaic systems are installed on selected public schools on the Big Island, Hawaii. The participating school will own the photovoltaic facility and use the energy produced by the system at no cost. Contributions received from the participants in this Green Pricing Program Provision are used to help fund this pilot program.

Other renewable energy projects may be developed in the future as part of the Company's Green Pricing Program, depending on the availability of contributions received from this Green Pricing Program Provision.

VOLUNTARY PARTICIPATION:

1) Participation in the Green Pricing Program through the Green Pricing Program Provision, is voluntary and may be terminated by the participant at any time.

2) Any resident/non-resident of the Big Island, Hawaii may contribute to the Green Pricing Program through the Green Pricing Program Provision by completing a standard program sign-up form which indicates the participant's mailing address, electric service account number (if participant is currently a HELCO customer), and the contribution payment option desired. The Green Pricing Program Provision contribution payment options are listed below.

Superseding Revised Sheet No. 82A
Effective January 1, 1999

REVISED SHEET NO. 82A
Effective

GREEN PRICING PROGRAM PROVISION (Continued)

3. A participant may terminate his/her voluntary contribution to the Green Pricing Program at any time by submitting a written or telephonic request to the Company to terminate participation in the Green Pricing Program Provision.

CONTRIBUTION PAYMENT OPTIONS:

A participant will specify the amount of his/her voluntary contribution (in whole dollars) and shall elect one of the following payment options:

Option 1: Monthly Contribution - the participant will be billed monthly based on the participant's specified dollar contribution amount.

Option 2: One Time Contribution - the participant will be billed one time for one lump sum contribution.

TERMS AND CONDITIONS:

1. Payments received by the Company shall be applied first to the participant's outstanding electric service bill balance, if any, and the remainder shall be applied to the participant's contribution to the Green Pricing Program under the Green Pricing Program Provision.

2. Electric Service will not be terminated if the participant fails to make contribution payments under the Green Pricing Program Provision.

3. The Company may terminate a participant's participation in the Green Pricing Program Provision, if the participant fails to make contribution payments for two (2) consecutive months.

4. The Company's late payment charge shall not apply to the participant's voluntary contributions under the Green Pricing Program Provision.

Superseding Revised Sheet No. 19
Effective March 15, 1991

REVISED SHEET NO. 19
Effective

RULE NO 7

Discontinuance and Restoration of Service

A. REASONS FOR DENYING SERVICE

The Company may refuse or discontinue service for any of the reasons listed below:

1. Without notice in the event of a condition determined by the Company to be hazardous. The Company shall have the right to refuse service to any applicant and to refuse or discontinue service to any customer whose wire, appliances, apparatus, or other equipment, or use thereof shall be determined by the Company to be unsafe or in violation of applicable laws, ordinances, rules or regulations of any public authority, or if any condition exists upon the applicant's or customer's premises shall be determined by the Company to endanger the Company's service facilities;

   The Company does not assume any duty of inspecting or repairing any applicant's or customer's wire, appliances, apparatus, or other equipment or any part thereof and assumes no liability therefor;

2. Without notice in the event of customer use of equipment in such a manner as to adversely affect the Company's equipment or the Company's service to others;

3. Without notice in the event of tampering with the equipment furnished and owned by the Company;

4. Without notice in the event of unauthorized use or use in violation of applicable laws, ordinances, rules, or regulations of any public authority;

5. For violation of and/or non-compliance with the Company's tariff or rules on file with and approved by the Commission. The Company may discontinue service to a customer if after written notice of such non-compliance the customer fails to comply within 5 days after date of presentation of such notice or within such other period of time after date of presentation of such notice as may be specified in such notice;

6. For failure of the customer to fulfill his contractual obligations for service and/or facilities subject to regulation by the Commission;

Superseding Revised Sheet No. 20
Effective March 15, 1991

REVISED SHEET NO. 20
Effective

Rule No. 7 (Continued)

7. For failure of the customer to permit the Company reasonable access to its equipment;

8. For non-payment of bill provided that the Company has made a reasonable attempt to effect collection and has given the customer written notice that he has at least 5 days, excluding Sundays and holidays, in which to make settlement on his account or have his service denied;

9. If, for an applicant's convenience, the Company should provide service before credit is established or should continue service to a customer when credit has not been re-established in accordance with Rule No. 5 and he fails to establish or re-establish his credit within 5 days after date of presentation of written notice to do so or within such other period of time after date of presentation of such notice as may be specified in such notice, the Company may discontinue service;

10. For failure of the customer to furnish such service, equipment, permits, certificates, and/or rights-of-way, as shall have been specified by the Company as a condition to obtaining service, or in the event such equipment or permissions are withdrawn or terminated; or

11. For fraud against the Company.

Unless otherwise stated, the customer shall be allowed a reasonable time in which to comply with the rule before service is discontinued. No service shall be discontinued on the day preceding or day or days on which the Company's business office is closed unless provisions are made for payment or reconnection on days when the Company's business offices are closed, except as provided in Rules 7A1 and 7A2.

B. CUSTOMER'S REQUEST FOR SERVICE DISCONTINUANCE

When a customer desires to terminate his responsibility for service, he shall give the Company not less than 2 days notice and state the date on which he wishes the termination to become effective. A customer may be held responsible for all service furnished at the premises until 2 days after receipt of such notice by the Company or until the date of termination specified in the notice, whichever date is later.

Superseding Revised Sheet No. 20A
Effective October 9, 1992

REVISED SHEET NO. 20A
Effective

Rule No. 7 (Continued)

C. SERVICE ESTABLISHMENT AND RECONNECTION CHARGE

The Company shall require payment of $20.00 for each establishment, supersedure, or re-establishment of electric service to any customer. This service establishment charge is in addition to the charges calculated in accordance with the applicable schedule and will be required each time an account is opened, including a turn on or reconnection of electric service or a change of customer which requires a meter reading.

When the customer requests that electric service be turned on or reconnected outside of regular business hours, an additional charge of $25.00 will be charged.

Superseding Revised Sheet No. 21
Effective February 21, 1995

REVISED SHEET NO. 21
Effective

RULE NO. 8

Rendering and Payment of Bills

A. RENDERING OF BILLS

1. Billing Period

Bills for electric service may be rendered monthly or bimonthly at the option of the Company, except that bills based on measured monthly maximum demand shall be rendered monthly. Bimonthly bills will be computed by doubling the size of the monthly energy blocks and the monthly amount of the capacity or minimum charge.

2. Metered Service

Bills for metered service will be based on meter registration. Meters will be read as required for the preparation of regular bills, opening bills and closing bills.

It may not be possible always to read meters on the same day of the month, and should a bimonthly billing period contain less than 54 days or more than 66 days or should a monthly billing period contain less than 27 days or more than 33 days, a pro rata adjustment in the bill will be made.

3. Pro Rata Adjustment

Except as provided below, all bills for electric service rendered for periods of less than 54 days or more than 66 days on a bimonthly billing period, or for periods of less than 27 days or more than 33 days on a monthly billing period will be computed in accordance with the applicable schedule, but the size of the energy blocks, and the amount of the capacity demand, or minimum charge, specified therein, will be prorated on the basis of the ratio of the number of days in the period to the number of days in an average bimonthly or monthly period, which for this purpose shall be 60 days and 30 days, respectively.

RULE NO. 8 - Continued

When the total period of service is less than 34 days, no proration will be made, and no bill for such a service period shall be less than the specified monthly capacity, demand, or minimum charge, except, when temporary service is furnished and the customer has paid the estimated cost of installing and removing the service facilities, proration will be made.

B. READING OF SEPARATE METERS NOT COMBINED

For the purpose of making charges and billing, each meter upon the customer's premises will be considered separately and the readings of two or more meters will not be combined, except where the Company, for engineering and operating reasons, installs more than one meter.

C. PAYMENT OF BILLS

All bills are due and payable on the date of presentation, and payment shall be made at a Company business office or to an authorized representative or agent.

Bills for connection or reconnection of service, payments for deposits, and payments to reinstate deposits as required by these rules shall be paid before service will be connected or reconnected.

D. LATE PAYMENT CHARGE

1. A late payment charge of 1% shall be applied to any unpaid electric service-related account balances excluding any unpaid late payment charges existing when the bill is calculated for billing purposes, provided the billing period is not less than 20 days since the last bill.
2. A late payment charge of 0.83% per month (or 10% per year) shall be applied to any other customer account receivables (OCARS) excluding any unpaid late payment charges existing when the unpaid account balance is calculated for billing purposes, provided the billing period is not less than 20 days since the last bill. A late payment charge provision specified in a written contract shall supersede the 0.83% per month late payment charge.

Superseding Sheet No. 22A
Effective February 21, 1995

REVISED SHEET NO. 22A
Effective

RULE NO. 8 - Continued

3. As a guide to customers, electric service-related bills will show the due date when payment must be received by the Company, in order to avoid late payment charge. Customers should allow time for the mailing and processing of customer payments.

E. RETURNED PAYMENT CHARGE

Payment by check or by form of electronic transfer for any service covered herein which is not honored by the financial institution on which it is issued will result in a fee of $16.00 to the customer.

F. FIELD COLLECTION CHARGE

The Company shall require payment of $20.00 for any field call to the service location necessitated by the customer's non-payment of bills or for failure otherwise to comply with the tariff provided that service is not disconnected and the unpaid bill is successfully collected.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE
(Present Rates Eff. 02/15/01)

SINGLE PHASE

KWH	PRESENT RATES $/BILL	PROPOSED RATES $/BILL	INCREASE $	INCREASE %
---	------	------	-------	-------
100	38.14	39.27	1.13	2.96
200	66.27	68.54	2.27	3.43
300	94.40	97.81	3.41	3.61
400	122.54	129.19	6.65	5.43
500	150.68	160.57	9.89	6.56
600	178.81	191.95	13.14	7.35
700	206.95	223.33	16.38	7.91
800	235.08	254.71	19.63	8.35
900	263.21	286.09	22.88	8.69
1,000	291.35	317.47	26.12	8.97
1,100	319.49	349.68	30.19	9.45
1,200	347.62	381.89	34.27	9.86
1,300	375.75	414.10	38.35	10.21
1,400	403.89	446.31	42.42	10.50
1,500	432.03	478.53	46.50	10.76
2,000	572.70	639.58	66.88	11.68
2,500	713.38	800.64	87.26	12.23
3,000	854.05	961.69	107.64	12.60
5,000	1,416.75	1,605.91	189.16	13.35
10,000	2,823.50	3,216.47	392.97	13.92

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE R: RESIDENTIAL SERVICE
(Present Rates Eff. 02/15/01)

THREE PHASE

KWH	PRESENT RATES $/BILL	PROPOSED RATES $/BILL	INCREASE $	INCREASE %
100	42.64	43.77	1.13	2.65
200	70.77	73.04	2.27	3.21
300	98.90	102.31	3.41	3.45
400	127.04	133.69	6.65	5.23
500	155.18	165.07	9.89	6.37
600	183.31	196.45	13.14	7.17
700	211.45	227.83	16.38	7.75
800	239.58	259.21	19.63	8.19
900	267.71	290.59	22.88	8.55
1,000	295.85	321.97	26.12	8.83
1,100	323.99	354.18	30.19	9.32
1,200	352.12	386.39	34.27	9.73
1,300	380.25	418.60	38.35	10.09
1,400	408.39	450.81	42.42	10.39
1,500	436.53	483.03	46.50	10.65
2,000	577.20	644.08	66.88	11.59
2,500	717.88	805.14	87.26	12.16
3,000	858.55	966.19	107.64	12.54
5,000	1,421.25	1,610.41	189.16	13.31
10,000	2,828.00	3,220.97	392.97	13.90

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE NON-DEMAND
(Present Rates Eff. 02/15/01)

SINGLE PHASE

KWH	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
100	58.36	67.25	8.89	15.23
200	88.72	99.51	10.79	12.16
300	119.07	131.76	12.69	10.66
400	149.43	164.01	14.58	9.76
500	179.79	196.27	16.48	9.17
600	210.15	228.52	18.37	8.74
700	240.51	260.77	20.26	8.42
800	270.86	293.03	22.17	8.19
900	301.22	325.28	24.06	7.99
1,000	331.58	357.54	25.96	7.83
2,000	635.17	680.07	44.90	7.07
3,000	938.75	1,002.61	63.86	6.80
4,000	1,242.34	1,325.14	82.80	6.66
5,000	1,545.92	1,647.68	101.76	6.58
10,000	3,063.84	3,260.35	196.51	6.41

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE G: GENERAL SERVICE NON-DEMAND
(Present Rates Eff. 02/15/01)

THREE PHASE

KWH	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
100	78.36	89.25	10.89	13.90
200	108.72	121.51	12.79	11.76
300	139.07	153.76	14.69	10.56
400	169.43	186.01	16.58	9.79
500	199.79	218.27	18.48	9.25
600	230.15	250.52	20.37	8.85
700	260.51	282.77	22.26	8.54
800	290.86	315.03	24.17	8.31
900	321.22	347.28	26.06	8.11
1,000	351.58	379.54	27.96	7.95
2,000	655.17	702.07	46.90	7.16
3,000	958.75	1,024.61	65.86	6.87
4,000	1,262.34	1,347.14	84.80	6.72
5,000	1,565.92	1,669.68	103.76	6.63
10,000	3,083.84	3,282.35	198.51	6.44

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND
(Present Rates Eff. 02/15/01)

SINGLE PHASE

KW	KWH	KWH/KW	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
25	2,500	100	844.40	992.85	148.45	17.58
25	5,000	200	1,480.80	1,646.69	165.89	11.20
25	10,000	400	2,642.73	2,843.53	200.80	7.60
25	12,500	500	3,198.67	3,416.92	218.25	6.82
25	15,000	600	3,754.62	3,990.31	235.69	6.28
50	5,000	100	1,655.80	1,946.69	290.89	17.57
50	10,000	200	2,928.59	3,254.38	325.79	11.12
50	20,000	400	5,252.46	5,648.05	395.59	7.53
50	25,000	500	6,364.35	6,794.84	430.49	6.76
50	30,000	600	7,476.23	7,941.62	465.39	6.22
100	10,000	100	3,278.59	3,854.38	575.79	17.56
100	20,000	200	5,824.18	6,469.76	645.58	11.08
100	40,000	400	10,471.92	11,257.10	785.18	7.50
100	50,000	500	12,695.69	13,550.67	854.98	6.73
100	60,000	600	14,919.46	15,844.24	924.78	6.20
300	30,000	100	9,769.77	11,485.14	1,715.37	17.56
300	60,000	200	17,406.54	19,331.28	1,924.74	11.06
300	120,000	400	31,349.76	33,693.30	2,343.54	7.48
300	150,000	500	38,021.07	40,574.01	2,552.94	6.71
300	180,000	600	44,692.38	47,454.72	2,762.34	6.18

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE J: GENERAL SERVICE DEMAND
(Present Rates Eff. 02/15/01)

THREE PHASE

KW	KWH	KWH/KW	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
25	2,500	100	867.40	1,018.85	151.45	17.46
25	5,000	200	1,503.80	1,672.69	168.89	11.23
25	10,000	400	2,665.73	2,869.53	203.80	7.65
25	12,500	500	3,221.67	3,442.92	221.25	6.87
25	15,000	600	3,777.62	4,016.31	238.69	6.32
50	5,000	100	1,678.80	1,972.69	293.89	17.51
50	10,000	200	2,951.59	3,280.38	328.79	11.14
50	20,000	400	5,275.46	5,674.05	398.59	7.56
50	25,000	500	6,387.35	6,820.84	433.49	6.79
50	30,000	600	7,499.23	7,967.62	468.39	6.25
100	10,000	100	3,301.59	3,880.38	578.79	17.53
100	20,000	200	5,847.18	6,495.76	648.58	11.09
100	40,000	400	10,494.92	11,283.10	788.18	7.51
100	50,000	500	12,718.69	13,576.67	857.98	6.75
100	60,000	600	14,942.46	15,870.24	927.78	6.21
300	30,000	100	9,792.77	11,511.14	1,718.37	17.55
300	60,000	200	17,429.54	19,357.28	1,927.74	11.06
300	120,000	400	31,372.76	33,719.30	2,346.54	7.48
300	150,000	500	38,044.07	40,600.01	2,555.94	6.72
300	180,000	600	44,715.38	47,480.72	2,765.34	6.18

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING,
AIR-CONDITIONING, & REFRIGERATION SVC
(Present Rates Eff. 02/15/01)

SINGLE PHASE

KW	KWH	KWH/KW	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
10	1,000	100	347.17	388.18	41.01	11.81
10	2,000	200	596.34	652.37	56.03	9.40
10	3,000	300	845.51	916.55	71.04	8.40
10	4,000	400	1,094.68	1,180.73	86.06	7.86
25	2,500	100	825.92	919.46	93.53	11.32
25	5,000	200	1,448.85	1,579.92	131.07	9.05
25	7,500	300	2,071.77	2,240.37	168.61	8.14
25	10,000	400	2,694.69	2,900.83	206.14	7.65
50	5,000	100	1,623.85	1,804.92	181.07	11.15
50	10,000	200	2,869.69	3,125.83	256.14	8.93
50	15,000	300	4,115.54	4,446.75	331.21	8.05
50	20,000	400	5,361.38	5,767.66	406.28	7.58
100	10,000	100	3,219.69	3,575.83	356.14	11.06
100	20,000	200	5,711.38	6,217.66	506.28	8.86
100	30,000	300	8,203.07	8,859.49	656.42	8.00
100	40,000	400	10,694.76	11,501.32	806.56	7.54

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE H: COMMERCIAL COOKING, HEATING, AIR-CONDITIONING, & REFRIGERATION SVC
(Present Rates Eff. 02/15/01)

THREE PHASE

KW	KWH	KWH/KW	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
10	1,000	100	364.17	408.18	44.01	12.09
10	2,000	200	613.34	672.37	59.03	9.62
10	3,000	300	862.51	936.55	74.04	8.58
10	4,000	400	1,111.68	1,200.73	89.06	8.01
25	2,500	100	842.92	939.46	96.53	11.45
25	5,000	200	1,465.85	1,599.92	134.07	9.15
25	7,500	300	2,088.77	2,260.37	171.61	8.22
25	10,000	400	2,711.69	2,920.83	209.14	7.71
50	5,000	100	1,640.85	1,824.92	184.07	11.22
50	10,000	200	2,886.69	3,145.83	259.14	8.98
50	15,000	300	4,132.54	4,466.75	334.21	8.09
50	20,000	400	5,378.38	5,787.66	409.28	7.61
100	10,000	100	3,236.69	3,595.83	359.14	11.10
100	20,000	200	5,728.38	6,237.66	509.28	8.89
100	30,000	300	8,220.07	8,879.49	659.42	8.02
100	40,000	400	10,711.76	11,521.32	809.56	7.56

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE P: LARGE POWER SERVICE
(Present Rates Eff. 02/15/01)

KW	MWH	KWH/KW	PRESENT $/BILL	PROPOSED $/BILL	INCREASE $	INCREASE %
300	60	200	18,286.20	20,785.94	2,499.74	13.67
300	120	400	31,514.28	33,913.76	2,399.48	7.61
300	150	500	37,827.42	40,176.77	2,349.35	6.21
300	180	600	44,140.56	46,439.78	2,299.22	5.21
300	210	700	50,453.70	52,702.79	2,249.09	4.46
500	100	200	30,227.00	34,309.90	4,082.90	13.51
500	200	400	52,273.80	56,189.60	3,915.80	7.49
500	250	500	62,795.70	66,627.95	3,832.25	6.10
500	300	600	73,317.60	77,066.30	3,748.70	5.11
500	350	700	83,839.50	87,504.65	3,665.15	4.37
1,500	300	200	89,431.00	101,429.70	11,998.70	13.42
1,500	600	400	155,571.40	167,068.80	11,497.40	7.39
1,500	750	500	187,137.10	198,383.85	11,246.75	6.01
1,500	900	600	218,702.80	229,698.90	10,996.10	5.03
1,500	1,050	700	250,268.50	261,013.95	10,745.45	4.29
5,000	1,000	200	296,645.00	336,349.00	39,704.00	13.38
5,000	2,000	400	517,113.00	555,146.00	38,033.00	7.35
5,000	2,500	500	622,332.00	659,529.50	37,197.50	5.98
5,000	3,000	600	727,551.00	763,913.00	36,362.00	5.00
5,000	3,500	700	832,770.00	868,296.50	35,526.50	4.27
10,000	2,000	200	592,665.00	671,948.00	79,283.00	13.38
10,000	4,000	400	1,033,601.00	1,109,542.00	75,941.00	7.35
10,000	5,000	500	1,244,039.00	1,318,309.00	74,270.00	5.97
10,000	6,000	600	1,454,477.00	1,527,076.00	72,599.00	4.99
10,000	7,000	700	1,664,915.00	1,735,843.00	70,928.00	4.26

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 - TY 2006 REBUTTAL
PRESENT RATES & PROPOSED RATES
SCHEDULE F: PUBLIC STREET LIGHTING
(Present Rates Eff. 02/15/01)

MONTHLY USE			PRESENT $	PROPOSED $	INCREASE $	INCREASE %
ENERGY CHARGE						
KW	KWH	KWH/KW				
1	150	150	47.59	52.03	4.44	9.32
1	340	340	96.10	106.16	10.06	10.47
5	750	150	237.97	260.17	22.20	9.33
5	1700	340	480.49	530.81	50.32	10.47
10	1500	150	475.94	520.34	44.40	9.33
10	3400	340	960.97	1,061.62	100.65	10.47
25	3750	150	1,189.84	1,300.85	111.01	9.33
25	8500	340	2,402.43	2,654.04	251.61	10.47
50	7500	150	2,379.68	2,601.70	222.02	9.33
50	17000	340	4,804.85	5,308.09	503.24	10.47
100	15000	150	4,759.37	5,203.40	444.04	9.33
100	34000	340	9,609.70	10,616.17	1,006.47	10.47

Present rates effective February 15, 2001.

2006 Test Year ECAF:
@ present rates = 8.998 cents/kwh
@ proposed rates = 0.000 cents/kwh

REBUTTAL TESTIMONY OF
WARREN H.W. LEE

PRESIDENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Results of Operations, including Revenue Requirements, Rate Increase Implementation and Summary

INTRODUCTION

Q. Please state your name and business address.

A. My name is Warren H.W. Lee and my business address is 1200 Kilauea Avenue, Hilo, Hawaii.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits and workpapers as HELCO T-1, HELCO RT-1, and HELCO T-21.

Q. What will you address in this testimony?

A. In this testimony, I will address HELCO's Results of Operations and Revenue Requirements for the 2006 test year, and discuss the proposed implementation of the requested increase.

RESULTS OF OPERATIONS AND REVENUE REQUIREMENTS

Q. What is HELCO's rebuttal position with respect to revenue requirements for the 2006 test year at this point in this proceeding?

A. HELCO's rebuttal testimonies and exhibits support normalized 2006 test year revenue requirements of $348,637,600, based on the settlement with the Division of Consumer Advocacy ("Consumer Advocate") as shown in HELCO-R-2101. (These amounts are based on February 1, 2006 fuel oil prices, an 8.33% return on average rate base and a 10.7 % return on common equity.) HELCO is requesting the Commission to grant the Company a revenue increase of $24,564,500 or 7.58% over revenues of $324,073,100 at present rates for a normalized 2006 test year.

Q. How much of a rate increase did HELCO request in its Application?

A. The total rate increase HELCO requested in its Application was $29,931,100 (based on February 1, 2006 fuel oil prices), or 9.24% over revenues at present rates for a normalized 2006 test year.

Q. What would HELCO's 2006 test year return on average rate base be for ratemaking purposes without rate relief?

A. Without rate relief, HELCO's most recent estimate of normalized Results of Operations (based on February 1, 2006 fuel prices) indicate a rate of return on average rate base of 4.47 %.

Q. What evidence has HELCO presented to the Commission to support its test year revenue requirements?

A. HELCO's normalized test year revenue requirements have been justified by a completely documented rate case evidentiary record. The reasons for HELCO's need for rate relief have been explained in HELCO's Application filed on May 5, 2006, with detailed discussion included in HELCO's direct and rebuttal testimonies, and associated exhibits and workpapers. The evidentiary record has subsequently been further developed by HELCO's responses to the Division of Consumer Advocacy's ("Consumer Advocate") information requests.

Q. Does this documentation represent all of the evidentiary record prior to the evidentiary hearing?

A. No. The Consumer Advocate has submitted written testimonies, exhibits and workpapers that included information based on documentation provided in writing by HELCO as discussed above, as well as informal meetings and telephone conversations at the staff level between HELCO and the Consumer Advocate. The Consumer Advocate also provided responses to HELCO's information requests.

In addition, the Keahole Defense Coalition, Inc. ("KDC") filed a written position statement and responded to HELCO's information requests.

Q. Do the results of operations in HELCO-R-2101 incorporate the agreements reached by the parties in the settlement discussions described in HELCO RT-1?

A. Yes. As explained in HELCO RT-1, HELCO and the Consumer Advocate have resolved all revenue requirement issues and some of the rate design issues. In the coming days, HELCO and the Consumer Advocate will continue settlement discussions to resolve the remaining rate design issues.

Q. Is the record as described above sufficient for the Commission to make an informed decision on the revenue requirements for the 2006 test year?

A. Yes, it is. Although the Company expects the remaining rate design issues to be resolved quickly, resolution of those issues will have no impact on the test year revenue requirements or the revenue increase in this proceeding.

Q. Did the Company incorporate all of the settlement impacts into the cost of service study and rate design presented in its rebuttal testimony (HELCO RT-20)?

A. No. Settlement discussions between HELCO and the Consumer Advocate continued through March 21, 2006. There was not sufficient time to redo the cost of service study and rate design according to the settlement revenue requirements by the filing date of the Company's rebuttal testimony. The cost of service study and rate design are based on the "pre-settlement" results of operations shown on HELCO-R-2102. Further, settlement discussions on rate design have not yet concluded.

Q. Please explain the "pre-settlement" results of operations.

A. The pre-settlement results of operations incorporate certain adjustments to the results of operations submitted in HELCO-2101. These adjustments include corrections of errors, updates and changes which the Company made to its test year estimates between the time HELCO filed its application and the beginning of March 2007, prior to the commencement of settlement discussions with the Consumer Advocate. Some of these adjustments were conversions to recorded 2006 numbers. In addition, certain adjustments were made base on the Consumer Advocate's proposed test year estimates, which the Company intended to include in its settlement proposal to minimize the number of issues between HELCO and the Consumer Advocate. (In other words, the pre-settlement results of operations included some of the adjustments later agreed to in the settlement negotiations.

Q. Please describe some of the more significant adjustments included in the pre-settlement results of operations.

A. Below are some of the significant adjustments to the Company's direct testimony test year estimates that were included in the pre-settlement results of operations:

- Capitalization - updated HELCO's capitalization amounts by type of security according to December 31, 2006 recorded balances
- Common Equity - restored common equity for AOCI charges related to pension and OPEB plans as of December 31, 2006
- Net Cost of Plant in Service - increased the end of test year balance of net cost of plant in service by $3,279,000 to reflect December 31, 2006 recorded amounts
- Unamortized CIAC - increased the end of test year balance by $1,787,000 to reflect December 31, 2006 recorded
- Customer Advances – increased the end of test year balance by $2,526,000 to reflect December 31, 2006 recorded
- Accumulated Deferred Income Taxes - increased the beginning of test year balance by $1,311,000 and the end of test year balance by

$1,434,000 to incorporate certain adjustments proposed by the Consumer Advocate

- Fuel Expense, Purchased Power Expense, ECAC Revenue, Fuel Inventory – Update according to rebuttal run of production simulation model
- Production Expense – included Consumer Advocate adjustment in CA-101, Schedules C-3 (CA-IR-447 adjustments), C-4 (labor adjustment) and C-6 (LPT replacement), which amounted to a reduction of $1,617,000 in test year expense, and which were later included in the settlement agreement.
- Transmission and Distribution Expenses – included Consumer Advocate adjustment in CA-101, Schedule C-14 (CA-IR-447 adjustments), which amounted to a reduction of $132,000 in test year expense
- Customer Service – included Consumer Advocate adjustment in CA-101, Schedule C-9 (reclassification of DSM expenses) and adjustment based on Schedule C-11 (customer service project adjustments), but updated for December 31, 2006 recorded amounts, which amounted to a reduction of $243,000 in test year expense
- Administrative and General – included Consumer Advocate adjustments in CA-101, Schedules C-15 (T&D training adjustment) and C-21 (CA-IR-447 adjustments), which amounted to an increase of $190,000 in test year expense
- Section 199 Income Tax Deduction – included Consumer Advocate adjustment in CA-101, Schedule C-20 which reduced income tax expense by $160,000

Q. What revenue increase was reflected in the pre-settlement results of operations?

A. The pre-settlement results of operations (HELCO-R-2102) reflected a revenue increase of $27,051,900 based on February 1, 2006 fuel prices, an 8.61% return on average rate base and an 11.25% return on common equity. The pre-settlement results of operations did not include amortization of the pension asset, which result from the Consumer Advocate's proposed pension tracking mechanism.

Q. Will the Company update its cost of service study and rate design to incorporate the settlement results?

A. Yes. HELCO will revise its cost of service study and rate design as soon as the settlement discussions on the remaining rate design issues are concluded.

<u>RATE INCREASE IMPLEMENTATION</u>

Q. How does HELCO propose to implement its proposed rate increase?

A. HELCO proposes to implement the proposed rate increase in two steps:

1) Interim Rate Increase
2) Final Increase

Q. What is HELCO proposing for the interim rate increase?

A. HELCO proposes an interim rate increase in an amount equal to the increase in rates to which the Commission believes HELCO is "probably entitled" based on the evidentiary record before it, in accordance with H.R.S. Section 269-16(d) which states:

> "...if the commission has not issued its final decision on a public utility's rate application within the nine-month period stated in this section, the commission, within one month after the expiration of the nine-month period, shall render an interim decision allowing the increase in rates, fares and charges, if any to which the commission, based on the evidentiary record before it, believes the public utility is probably entitled. The

> commission may postpone its interim rate decision for thirty days if the commission considers the evidentiary hearings incomplete..."

HELCO filed its application on May 5, 2006.

On March 27, 2007, HELCO is filing a statement of probable entitlement which specifies its requested interim increase, based on the evidence before the Commission. HELCO requests that it be allowed to implement its proposed rate increase as soon as practicable.

Q. How should the Commission determine what the Company is "probably entitled" to?

A. The amount of the interim increase to which HELCO has shown "probable entitlement" should include the amount of the rate increase that is "uncontested" and those amounts for which probable entitlement has been demonstrated. The starting point for the Commission in reviewing contested issues should be its own decisions in prior cases. In addition, the Commission should not accept an estimate for purposes of determining the interim where HELCO has demonstrated that a computational or input error was made by a party or participant to arrive at its estimate, or where later available information demonstrates the unreasonableness of the estimate, or where the estimate is clearly too low. The same holds true for HELCO's estimates. The Commission's guidance from prior interim decision and orders is addressed in the probable entitlement filing.

Q. How will HELCO implement the interim rate increase?

A. HELCO proposes to implement the interim rate increase as surcharges to the various classes based on a percentage of the customer's bill (exclusive of Energy Cost Adjustment charges and other surcharges) with the allocation to each rate class consistent with the likely final rate increase allocation. (Thus, the Company can implement an interim increase with this method even if the rate design issues have not been fully resolved.) This implementation method was used for HELCO in Docket Nos. 99-0207 and 94-0140, for MECO in Docket Nos. 94-0345 and 97-0346 and for HECO in Docket No. 04-0113.

Q. When does HELCO propose to make the final increase effective?

A. The final increase would become effective when the Commission issues its final decision and order to provide the balance of the total requested increase authorized but not included in the interim increase.

Q. What rate mechanism does HELCO propose to implement the final increase?

A. HELCO proposes to implement the final increase with the proposed rates and charges that will be based on the rate design that results from its settlement discussions with the Consumer Advocate, or with such other rates and charges as approved by the Commission.

SUMMARY

Q. Please summarize your testimony?

A. HELCO requests Commission approval of a general rate increase and revised rate and rule changes to be granted in the steps outlined above.

In order for HELCO to maintain its financial integrity and its ability to attract capital for its capital expenditures, it is essential that the Commission grant an appropriate interim increase as soon as practicable.

The evidence presented by HELCO has demonstrated the reasonableness of this request and has satisfied HELCO's burden of proof.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company
Settlement
Results of Operations
2006
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 8.33% Return on Average Rate Base
Electric Sales Revenue	323,147.7	24,393.4	347,541.1
Other Operating Revenue	925.4	171.1	1,096.5
TOTAL OPERATING REVENUES	324,073.1	24,564.5	348,637.6
Fuel	78,583.5		78,583.5
Purchased Power	117,209.7		117,209.7
Production	21,041.2		21,041.2
Transmission	2,340.7		2,340.7
Distribution	6,364.0		6,364.0
Customer Accounts	3,185.6		3,185.6
Allowance for Uncoll. Accounts	387.8	29.3	417.1
Customer Service	1,508.8		1,508.8
Administration & General	15,213.5		15,213.5
Operation and Maintenance	245,834.8	29.3	245,864.1
Depreciation & Amortization	28,772.0		28,772.0
Amortization of State ITC	(490.3)		(490.3)
Taxes Other Than Income	30,178.3	2,175.7	32,354.0
Interest on Customer Deposits	55.8		55.8
Income Taxes	3,624.2	8,700.1	12,324.3
TOTAL OPERATING EXPENSES	307,974.8	10,905.1	318,879.9
OPERATING INCOME	16,098.3	13,659.4	29,757.7
AVERAGE RATE BASE	360,408.3	(3,170.2)	357,238.1
RATE OF RETURN ON AVERAGE RATE BASE	4.47%		8.33%

Hawaii Electric Light Company
Pre-Settlement
Results of Operations
2006
($ Thousands)

	Present Rates	Additional Amount	Revenue Requirements to Produce 8.61% Return on Average Rate Base
Electric Sales Revenue	323,147.7	26,876.5	350,024.2
Other Operating Revenue	925.4	175.4	1,100.8
TOTAL OPERATING REVENUES	324,073.1	27,051.9	351,125.0
Fuel	78,583.5		78,583.5
Purchased Power	117,209.7		117,209.7
Production	21,423.2		21,423.2
Transmission	2,385.2		2,385.2
Distribution	6,482.5		6,482.5
Customer Accounts	3,185.6		3,185.6
Allowance for Uncoll. Accounts	387.8	32.3	420.1
Customer Service	2,008.8		2,008.8
Administration & General	12,659.5		12,659.5
Operation and Maintenance	244,325.8	32.3	244,358.1
Depreciation & Amortization	29,370.0		29,370.0
Amortization of State ITC	(501.0)		(501.0)
Taxes Other Than Income	30,199.3	2,396.3	32,595.6
Interest on Customer Deposits	55.8		55.8
Income Taxes	3,974.6	9,580.9	13,555.5
TOTAL OPERATING EXPENSES	307,424.5	12,009.5	319,434.0
OPERATING INCOME	16,648.6	15,042.4	31,691.0
AVERAGE RATE BASE	371,564.9	(3,491.2)	368,073.7
RATE OF RETURN ON AVERAGE RATE BASE	4.48%		8.61%

REBUTTAL TESTIMONY OF
ALAN K.C. HEE

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Energy Cost Adjustment Clause

INTRODUCTION

Q. Please state your name and business address.

A. My name is Alan K.C. Hee and my business address is 220 South King Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am the Manager of the Energy Services Department ("ESD") at Hawaiian Electric Company, Inc. ("HECO").

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I submitted supplemental testimony (HELCO ST-22) on the Energy Cost Adjustment Clause ("ECAC") and the Energy Policy Act of 2005.

Q. What is your area of responsibility in this proceeding?

A. First, as indicated by Mr. Lee in HELCO RT-1, I am adopting the section on the ECAC in the direct testimony of Mr. Peter Young (HELCO T-3). Since I submitted supplemental testimony on the ECAC, my adoption of Mr. Young's direct testimony on the ECAC will enable one witness to cover this subject area for the Company. My rebuttal testimony will cover HELCO's 2006 test year estimate of the ECAC and compliance of the ECAC as it relates to Act 162 (Session Laws of Hawaii, 2006). As indicated in my testimony below, there are no contested issues in the areas covered by Mr. Jeff Makholm (HELCO ST-23) or Mr. Gene Meehan (HELCO ST-24). Therefore, Mr. Makholm and Mr. Meehan will not submit rebuttal testimony.

Q. Please summarize your rebuttal testimony.

A. HELCO and the Consumer Advocate agree that the ECAC should be continued, that HELCO's ECAC complies with Act 162 (2006) and the existing sharing of fuel cost risk between HELCO's ratepayers and shareholders is appropriate. As a result of settlement discussions, the Consumer Advocate agrees with the Company's test year ECAC revenues at present rates which are based on the Company's proposed Energy Cost Adjustment ("ECA") factor, the Company's ECAC base costs and the Company's proposed sales heat rates. My rebuttal testimony addresses one issue of contention regarding the Consumer Advocate's recommendation for the Company to file a fuel plan. My rebuttal testimony explains that such a plan is not needed since the Company's fuel contracts are subject to Commission review and approval and are currently long term. The Company's current fuel contract amendments became effective on January 1, 2005 for a term of ten years.

ENERGY COST ADJUSTMENT FACTOR

Q. What are HELCO's test year estimates for the ECA factor at present and proposed rates?

A. HELCO's estimates of the ECA factor at present and proposed rates are 8.998 cents/kwh and 0.000 cents/kwh, respectively, as shown in HELCO-R-2201.

Q. How does the rebuttal ECA factor at present rates differ from direct testimony?

A. The ECA factor at present rates in this rebuttal testimony is slightly lower than the ECA factor in direct testimony, as shown in HELCO-R-2202.

Q. Why has the ECA factor at present rates changed from direct testimony?

A. The rebuttal ECA factor at present rates has been updated to reflect test year rebuttal estimates of fuel consumption, fuel expense, generation output, distributed generation ("DG") energy, and purchased power discussed by Ms. Giang in HELCO RT-4 and Mr. Verbanic in HELCO RT-5, as shown in HELCO-R-2203.

Q. Is HELCO still proposing to set the test year ECA factor at proposed rates to 0.000 cents/kwh?

A. Yes it is, as shown in HELCO-R-2204.

Q. What are the rebuttal avoided energy cost payment rates for the test year?

A. The rebuttal avoided energy cost payment rates are 17.40 cents/kwh (on-peak) and 14.08 cents/kwh (off-peak), as shown in HELCO-RWP-2204, page 15.

SALES HEAT RATE

Q. What are the test year sales heat rates that are to be used in the weighted efficiency factor in HELCO's proposed ECA Clause?

A. As shown on HELCO-R-2205, the rebuttal estimates of sales heat rates, in btu/kwh sales, are:

Central Station including Wind/Hydro	14,826
Steam	15,615
Diesel	13,526
Wind/Hydro	14,826

Q. How do the rebuttal sales heat rates differ from direct testimony?

A. As shown in HELCO-R-2205, HELCO's rebuttal sales heat rates are lower than the sales heat rates in direct testimony. On a percentage basis, the differences are very small.

Q. Why did the sales heat rates change from direct testimony?

A. The sales heat rates have been updated to reflect updated estimates of fuel consumption and the percentage of central station generation contribution to net system input, as discussed in Ms. Giang's rebuttal testimony.

AREAS OF AGREEMENT AND DISAGREEMENT

Q. In what areas do HELCO and the Consumer Advocate agree?

A. The parties agree that:

1) The ECA Clause should be continued,
2) The costs of startup propane should be passed through the ECAC to the extent these costs are not included in base rates,
3) A separate DG component should be added to the ECA Clause to recover DG fuel and transportation costs to the extent they are not recovered through base rates,
4) A weighted efficiency factor, with a three part sales heat rate, for HELCO's central station steam, central station diesel units, and wind and hydro units, should be incorporated in the ECA Clause,
5) The ECA factor at proposed rates should be reset to zero, and
6) HELCO's ECAC complies with Act 162 (2006) and the existing sharing of fuel cost risk between HELCO's ratepayers and shareholders is appropriate.

Q. Where in its testimony does the Consumer Advocate agree with the continuance of the ECA Clause?

A. The Consumer Advocate agrees that the ECAC should continue to be employed, in CA-T-1, on page 22, line 17 to page 23, line 3.

Q. Why does the Consumer Advocate agree that propane startup costs should be included in the ECAC?

A. As indicated in CA-T-2, page 45, lines 14 to 16, "Shipman and Hill propane costs are fuel related costs that are comparable to fuel costs for other HELCO generating units that are included in the ECAC."

Q. Where in testimony does the Consumer Advocate agree that a DG component should be included in the ECAC?

A. The Consumer Advocate agrees that a DG component should be included in the ECAC in CA-T-2, page 45, lines 10 to 20. The Consumer Advocate recommends that the DG component be subject to a DG fixed efficiency factor, but later in testimony, expresses no opposition to HELCO's proposal that the DG units not be subject to a fixed efficiency factor at this time because "The Company's DG units, however, are expected to provide only 0.01% of HELCO's energy requirements for the test year. . . . Accordingly, HELCO's proposed DG component is acceptable to the Consumer Advocate provided that HELCO will be required to continue to annually file calibration reports with the Commission and the Consumer Advocate." (CA-T-2, page 49, line 5, to page 50, line 1.)

Q. Does HELCO agree to continue to annually file calibration reports with the Commission and Consumer Advocate?

A. Yes. HELCO agrees to continue to file its calibration reports annually with the Commission and Consumer Advocate.

Q. Why does the Consumer Advocate agree with HELCO that a three part sales heat rate for HELCO's central station units and HELCO's wind and hydro units be incorporated into the ECAC?

A. The Consumer Advocate agrees with the three part sales heat rate because "This method should cause changes in fuel prices by fuel type to track generator efficiency and generator use by fuel type more closely than a single heat rate." (CA-T-2, page 46, lines 1 to 7.)

Q. What is the Consumer Advocate's ECAF at proposed rates?

A. In CA-215, the Consumer Advocate calculates the ECAF at proposed rates as -0.002 cents per kwh. However, because the Consumer Advocate embeds the Generation, DG, and Purchased Energy cost components into base rates, and because rounding causes the Consumer Advocate's calculation of the ECAF at proposed rates to not equal zero, it appears that the Consumer Advocate intended that its estimate of the ECAF at proposed rates is zero.

Q. Does the Consumer Advocate agree with HELCO that HELCO's ECAC complies with Act 162?

A. Yes. As stated by the Consumer Advocate in CA-T-2, page 8, lines 19 and 20, "The Company's proposed ECAC satisfies the requirements of Act 162 considerations." In particular, the Consumer Advocate notes that "The Company's ECAC provides a fair sharing of the risks of fuel costs changes between the Company and its ratepayers in a manner that preserves the integrity of the Company without the need for frequent rate filings." (CA-T-2, page 64, lines 3 to 6.)

In addition, the Consumer Advocate concludes that:

> The ECAC's fixed efficiency factors are thus an effective means of sharing the operating and performance risks between HELCO's ratepayers and shareholders.
>
> With respect to the risk of fuel cost changes due to changes in fuel prices, the ECAC passes such risks in price changes through to ratepayers. Because fuel prices are not within HELCO's control and HELCO is a price taker, it is not considered appropriate for HELCO to bear the risks of fuel cost changes due to price changes established by a global market." (CA-T-2, page 58, lines 15 through 22.)

Furthermore, the Consumer Advocate does not support fuel price hedging. Rather, "If the Company cannot achieve non-volatile fuel prices through its fuel purchasing plan, it would seem reasonable that customers who desire less fluctuation in their electric charges from month to month would have the option of levelizing their payments through budget billing that would not charge the customer more than it otherwise would pay over a period of one year." (CA-T-2, page 62, lines 4 to 9.)

Q. What is HELCO's plan to implement budget billing?

A. HELCO will explore an optional revenue neutral budget billing rate schedule for residential and Schedule G customers. Further, HELCO will submit to the Commission, within 12 months from the date of the Commission's final decision and order ("D&O") in this docket, a pilot budget billing program for its review. HELCO cannot currently implement budget billing using its existing customer information system ("CIS"). The new CIS, however, can handle budget billing, but is not expected to be in-service until the first half of 2008. Therefore, while HELCO may submit its pilot budget billing program and tariff for Commission review within 12 months of the Commission's final D&O in this docket, the schedule for actual implementation of the pilot depends on the in-service date for the new CIS.

Q. In what areas of the ECA Clause did the Consumer Advocate's testimony differ from HELCO's proposals?

A. The parties differed in the following areas:

1) The ECA factor at present rates
2) Sales heat rates, and
3) The necessity for filing a periodic fuel plan with the Commission.

Q. How does the Consumer Advocate's estimate for the test year ECA factor at present rates compare to the Company's rebuttal estimate?

A. As shown in HELCO-R-2206, the Consumer Advocate's estimate of the ECA factor at present rates of 8.621 cents/kwh is 0.377 cents/kwh lower than the Company's rebuttal estimate of 8.998 cents/kwh.

Q. Why is the Company's estimate for the test year ECA factor different from the Consumer Advocate's estimate?

A. HELCO's estimated rebuttal ECA factor is different because it is based on HELCO's estimates of test year fuel expense and fuel consumption, which are different from the Consumer Advocate's estimates of test year fuel expense and consumption. These differences are discussed in Ms. Giang's and Mr. Verbanic's rebuttal testimonies. In addition, the Consumer Advocate, in the calculation of its estimate of the ECA factor at present rates:

1) Inadvertently included DG fuel and transportation costs. (See HELCO/CA-IR-202 and 204.) These costs are not currently being recovered through the ECAC at present rates.
2) Inadvertently excluded fuel additive and inspection (Petrospec) costs. (See HELCO/CA-IR-206). These costs are currently included in the ECAC at present rates.
3) Inadvertently did not recalculate test year estimates of avoided cost and Schedule Q payment rates to reflect the Consumer Advocate's production simulation results. (See HELCO/CA-IR-207.)

Q. Were HELCO and the Consumer Advocate able to resolve this difference in recent settlement discussions in March 2007?

A. Yes. For settlement purposes, the Consumer Advocate accepted the Company's rebuttal test year ECAC revenue estimate of $103,297,000 at present rates as calculated in HELCO-R-302 in the rebuttal testimony of Ms. Colleen Miller (HELCO RT-3). This revenue amount at present rates was calculated using the ECA factor of 8.998 cents/kwh. The Consumer Advocate also agreed to the Company's ECAC base costs.

Q. How do the Consumer Advocate's estimated test year sales heat rates compare to the Company's test year estimates?

A. As shown in HELCO-R-2207, the Consumer Advocate's estimates of total central station (with wind/hydro) and steam unit sales heat rates are higher than HELCO's estimates. On the other hand, the Consumer Advocate's estimates of diesel unit and wind/hydro sales heat rates are lower than HELCO's estimates.

Q. Why are the Consumer Advocate's estimated sales heat rates different from the Company's test year rebuttal estimates?

A. The Consumer Advocate's and HELCO's estimated sales heat rates are different because the Consumer Advocate's estimated test year fuel consumption and percentage of central station generation contribution to net system input are different from HELCO's estimates. These differences are discussed in Ms. Giang's rebuttal testimony.

Q. Were HELCO and the Consumer Advocate able to resolve this difference in settlement discussions?

A. Yes. For settlement purposes, the Consumer Advocate accepted HELCO's rebuttal sales heat rates.

Q. What did the Consumer Advocate suggest the Company do to show that it has taken appropriate actions to acquire fuel at reasonable costs?

A. In CA-T-2, page 59, lines 9 to 14, Mr. Herz stated, "The Company should be required to prove that it has taken appropriate actions to acquire fuel at reasonable costs. This could be done through a process, which requires the Company to periodically file a fuel plan with the Commission. The purpose of the plan would be to assume that the Company is taking appropriate measures to acquire fuel at the lowest cost possible on behalf of its customers."

Q. What is HELCO's response to the Consumer Advocate's contention that HELCO be "required to prove that it has taken appropriate actions to acquire fuel at reasonable costs"?

A. HELCO agrees that it should take appropriate action to acquire fuel at reasonable costs, and HELCO already has taken such action. HELCO's position is that it would be unnecessary to require HELCO to periodically file a fuel plan with the Commission.

Q. Please explain what actions HELCO takes to acquire fuel at reasonable costs.

A. From time to time, HECO, on behalf of HELCO, negotiates long-term fuel supply contracts with the only two on-island refineries, Chevron Products Company ("Chevron") and Tesoro Hawaii Corporation ("Tesoro"). The Commission must approve these long-term fuel supply contracts. In its application for approval of the fuel supply contracts, HECO and HELCO must demonstrate that it has taken appropriate measures to responsibly and cost-effectively acquire its fuel supplies and related services (liquid petroleum terminalling and inter-island fuel barging, for example) in order to obtain the approval of the Commission. The contracts define, among other things, the formulae for pricing of the fuel. Pricing is tied to widely used industry indices.

HELCO's fuel prices are the result of fuel contracts that have been approved by the Commission. The current inter-island fuel contract, approved by the Commission in Docket No. 97-0396 on December 30, 1997 is the essential contractual basis of the fuel purchase arrangements still in effect.

As stated in the direct testimony of Ms. Giang in HELCO T-4 (page 19), Industrial Fuel Oil ("IFO") and diesel fuel are supplied by Chevron and Tesoro to HELCO under existing fuel supply contracts, which were extended and revised by amendments executed on April 12, 2004 and March 29, 2004, respectively. HELCO, along with HECO and MECO, submitted an application to the Commission for approval of these amendments on May 28, 2004 in Docket No. 04-0129. In the proceeding to review the appropriateness of the contract amendments, the Consumer Advocate submitted its Statement of Position on November 8, 2004 and stated that "the Consumer advocate hereby states that it does not object to Commission approval of the instant Application." These fuel supply contract amendments were approved by the Commission in Decision and Order No. 21523 issued on December 30, 2004, in Docket No. 04-0129 and were effective on January 1, 2005, and will be effective for a period of ten years.

Q. What is HELCO's response to the Consumer Advocate's suggestion that HELCO "periodically file a fuel plan with the Commission" to show that HELCO "is taking appropriate measures to acquire fuel at the lowest cost possible on behalf of its customers."

A. It would be unnecessary to require HELCO to periodically file a fuel plan with the Commission because pricing and supply of the fuel for HELCO is in accordance with the fuel supply contracts noted above. The appropriate time to review the pricing in long-term contracts is when the contracts are approved. In the case of HELCO's long-term contracts, the fuel supply contract amendments have already been approved by the Commission, and the Consumer Advocate supported such approval.

Q. Why would a fuel plan not be needed for the procurement of non-fossil fuels?

A. A fuel plan would not be needed because HELCO, or HECO on behalf of HELCO, would submit to the Commission for its review any contract for the procurement of non-fossil fuels and demonstrate at the time of review that it has taken appropriate measures to responsibly and cost-effectively acquire its fuel supplies and related services in order to obtain the approval of the Commission.

Q. Is "lowest possible cost" the appropriate standard for procurement of fuel?

A. No. "Lowest possible cost" is not the appropriate standard to apply in reviewing such contracts for two primary reasons. First, cost is not the only factor considered in procuring fuel. Other factors include, but are not limited to, availability of supply in the face of HELCO's fluctuating generation fuel demand (because HELCO's fuel consumption is affected by the availability and reliability of Independent Power Producers and the fluctuating outputs of as-available wind and hydro units), the reliability of the fuel suppliers' operations to safely deliver diesel fuel and IFO to HELCO, and the preference for fuels such as biofuels that are environmentally friendly and renewable, but whose price may be somewhat higher than the petroleum based fuels it is intended to replace.

Second, since HELCO's two fuel suppliers are the only two potential fuel sellers that have crude oil processing refineries and associated bulk petroleum product distribution infrastructure located in the State, another supplier, even if offering "the lowest cost possible" price of both diesel and No. 6 fuel oil, would either have to acquire such petroleum products from the same two oil refiners from which HELCO obtains its fuel or rely on imported products that meet HELCO's fuel specification requirements. There is uncertainty as to the logistics of how a potential supplier could import diesel fuel and IFO from the U.S. mainland or a foreign source in sufficient volume to supply the Company's needs. The uncertainties include, but are not limited to, the adequacy of petroleum storage infrastructure existing in the State, on Oahu, the Big Island or elsewhere, that would enable an off-shore supplier to sustain fuel deliveries to HELCO.

Q. Have HELCO and the Consumer Advocate attempted to resolve this difference in settlement discussions?

A. Discussions on this issue are ongoing and have not been resolved as of the filing date of this rebuttal testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.

TEST YEAR ENERGY COST ADJUSTMENT FACTORS
Rebuttal Testimony

(A)	(B)
ENERGY COST ADJUSTMENT FACTOR AT PRESENT RATES	ENERGY COST ADJUSTMENT FACTOR AT PROPOSED RATES
8.998 ¢/KWH	0.000 ¢/KWH

Reference:
Col (A): HELCO-R-2203
Col (B): HELCO-R-2204, pg 2

Hawaii Electric Light Company, Inc.

Comparison of Rebuttal Testimony versus
Direct Testimony Energy Cost Adjustment Factors
(¢/kwh)

Present Rates		
Rebuttal Testimony	Direct Testimony	Difference
8.998	9.003	-0.005

Proposed Rates		
Rebuttal Testimony	Direct Testimony	Difference
0.000	0.000	0.000

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Present Rates

Line			
1	Effective Date		2006 Test Year - Rebuttal
	Supercedes Factors of		
	HELCO GENERATION COMPONENT		
	FUEL PRICES, ¢/mmbtu		
2	Shipman Industrial		912.85
3	Hill Industrial		912.85
4	Puna Industrial		932.68
5	Keahole Diesel		1,502.48
6	Waimea Diesel		1,497.17
7	Hilo Diesel		1,479.95
8	Puna Diesel		1,480.64
9	Wind		0.00
10	Hydro		0.00
11	Dispersed		0.00
	BTU MIX, %		
12	Shipman Industrial		8.56
13	Hill Industrial		36.89
14	Puna Industrial		16.85
15	Keahole Diesel		27.99
16	Waimea Diesel		0.09
17	Hilo Diesel		0.52
18	Puna Diesel		4.15
19	Wind		0.27
20	Hydro		4.67
21	Dispersed		0.01
			100.00
22	COMPOSITE COST OF GENERATION, ¢/mmbtu		1,063.08
23	% Input to System kwh Mix		43.32
24	Efficiency Factor, mmbtu/kwh		0.014629
25	WEIGHTED COMPOSITE GEN COST, ¢/kwh (lines (22x23x24))		6.73704
26	BASE GEN. COST, ¢/mmbtu		469.72
27	Base % Input to Sys kwh Mix		27.09
28	Efficiency Factor, mmbtu/kwh		0.014629
29	WEIGHTED BASE GEN COST, ¢/kwh (lines (26x27x28))		1.8615
30	COST LESS BASE (line(25-29))		4.87554
31	Rev Tax Req Multiplier		1.0975
32	GENERATION FACTOR, ¢/kwh (line (30x31))		5.35091

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kwh		
33	HEP		12.274
34	PGV	On Peak	17.400
35	PGV	Off Peak	14.080
36	PGV Addt'l	On Peak	13.032
37	PGV Addt'l	Off Peak	12.032
38	Wailuku Hydro	On Peak	17.400
39	Wailuku Hydro	Off Peak	14.080
40	Hawi Renewable	On Peak	17.400
41	Hawi Renewable	Off Peak	14.080
42	Apollo (Kamaoa)	On Peak	14.790
43	Apollo (Kamaoa)	Off Peak	11.968
44	Other (>100 KW)	On Peak	17.400
45	Other (>100 KW)	Off Peak	14.080
46	Other (<100 KW)		15.830
	PURCHASED ENERGY KWH MIX, %		
47	HEP		59.18
48	PGV	On Peak	15.45
49	PGV	Off Peak	10.39
50	PGV Addt'l	On Peak	3.09
51	PGV Addt'l	Off Peak	2.36
52	Wailuku Hydro	On Peak	2.26
53	Wailuku Hydro	Off Peak	1.62
54	Hawi Renewable	On Peak	3.33
55	Hawi Renewable	Off Peak	1.50
56	Apollo (Kamaoa)	On Peak	0.48
57	Apollo (Kamaoa)	Off Peak	0.20
58	Other (>100 KW)	On Peak	0.07
59	Other (>100 KW)	Off Peak	0.05
60	Other (<100 KW)		0.02
			100.00
61	COMPOSITE COST OF PURCHASED ENERGY, ¢/kwh		13.631
62	% Input to System kwh Mix		56.68
63	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kwh (lines (61x62))		7.72605
64	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kwh		6.404
65	Base % Input to Sys kwh Mix		72.91
66	WEIGHTED BASE PURCH ENERGY COST, ¢/kwh (lines (64x65))		4.66916
67	COST LESS BASE(line(63 - 66))		3.05689
68	Loss Factor		1.087
69	Rev Tax Req Multiplier		1.0975
70	PURCHSD ENERGY FCTR, ¢/kwh (lines (67x68x69))		3.64682

LINE	SYSTEM COMPOSITE	
71	FUEL AND PURCHASED ENERGY FACTOR, ¢/kwh (lines (32+70))	8.99773
72	Not Used	0.000
73	Not Used	0.000
74	ECA Reconciliation Adjustment	0.000
75	ECA FACTOR, ¢/kwh (line(71+72+73+74))	8.998

Reference: HELCO-RWP-2203

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2006 Test Year - Rebuttal (page 1 of 2)

Line		
1	Effective Date	2006 Test Year - Rebuttal
2	Supercedes Factors of	

GENERATION COMPONENT

CENTRAL STATION WITH WIND/HYDRO COMPONENT

Line		
	FUEL PRICES, ¢/mmbtu	
3	Shipman Industrial	927.55
4	Hill Industrial	912.85
5	Puna Industrial	932.68
6	Keahole Diesel	1,502.48
7	Waimea Diesel	1,497.17
8	Hiko Diesel	1,479.95
9	Puna Diesel	1,480.64
10	Wind	0.00
11	Hydro	0.00
	BTU MIX, %	
12	Shipman Industrial	8.56
13	Hill Industrial	36.90
14	Puna Industrial	16.85
15	Keahole Diesel	27.99
16	Waimea Diesel	0.09
17	Hiko Diesel	0.52
18	Puna Diesel	4.15
19	Wind	0.27
20	Hydro	4.67
		100.00
21	COMPOSITE COST OF GENERATION, CNTRL STN+WIND/HYDRO ¢/mmbtu	1,064.43
22	% Input to System kWh Mix	43.31

EFFICIENCY FACTOR, mmbtu/kWh

Line	(A) Fuel Type	(B) Eff Factor mmbtu/kwh	(C) Percent of Cntrl Stn + Wind/Hydro	(D) Weighted Eff Factor
23	Industrial	0.015615	59.17	0.009239
24	Diesel	0.013526	35.90	0.004856
25	Other	0.014826	4.93	0.000731

(Lines 23, 24, 25): Col(B) x Col(C) = Col(D)

Line		
26	Weighted Efficiency Factor, mmbtu/kWh [lines 23(D) + 24(D) + 25(D)]	0.014826
27	WGTD. COMPOSITE CNTRL STN + WIND/HYDRO GEN COST, ¢/kWh (lines (21x22x26))	6.83485
28	BASE CNTRL STN + WND/HYDRO GEN. COST, ¢/mmbtu	1,064.43
29	Base % Input to Sys kWh Mix	43.31
30	Efficiency Factor, mmbtu/kwh	0.014826
31	WEIGHTED BASE CNTRL STN + WIND/HYDRO GEN COST ¢/kWh (lines (28x29x30))	6.83485
32	COST LESS BASE (line(27-31))	0.00000
33	Revenue Tax Req Multiplier	1.0975
34	CNTRL STN+WIND/HYDRO GENERATION FACTOR, ¢/kWh (line (32x33))	0.00000

DG ENERGY COMPONENT

Line		
35	COMPOSITE COST OF DG ENERGY, ¢/kWh	14.942
36	% Input to System kWh Mix	0.01
37	WTD COMP DG ENRGY COST, ¢/kWh (Lines 35 x 36)	0.00149
38	BASE DG ENERGY COMP COST	14.942
39	Base % Input to System kWh Mix	0.01
40	WTD BASE DG ENERGY COST, ¢/kWh (Line 38 x 39)	0.00149
41	Cost Less Base (Line 37 - 40)	0.00000
42	Loss Factor	1.090
43	Revenue Tax Req Multiplier	1.0975
44	DG FACTOR, ¢/kWh (Line 41 x 42 x 43)	0.00000

SUMMARY OF TOTAL GENERATION FACTOR, ¢/kWh

Line		
45	Cntrl Stn+Wind/Hydro (line 34)	0.00000
46	DG (line 44)	0.00000
47	TOTAL GENERATION FACTOR, ¢/kWh (lines 45 + 46)	0.00000

Reference: HELCO-RWP-2204

HAWAII ELECTRIC LIGHT COMPANY, INC.
ENERGY COST ADJUSTMENT (ECA) FILING
Proposed Rates

ENERGY COST ADJUSTMENT (ECA) FILING - 2006 Test Year - Rebuttal (page 2 of 2)

Line	PURCHASED ENERGY COMPONENT		
	PURCHASED ENERGY PRICE, ¢/kWh		
48	HEP		12.274
49	PGV	On Peak	17.400
50	PGV	Off Peak	14.080
51	PGV - Addt'l	On Peak	13.032
52	PGV - Addt'l	Off Peak	12.032
53	Wailuku Hydro	On Peak	17.400
54	Wailuku Hydro	Off Peak	14.080
55	Hawi Renewable Dev.	On Peak	17.400
56	Hawi Renewable Dev.	Off Peak	14.080
57	Apollo (Kamaoa)	On Peak	14.790
58	Apollo (Kamaoa)	Off Peak	11.968
59	Other (>100 KW)	On Peak	17.400
60	Other (>100 KW)	Off Peak	14.080
61	Other (<100 KW)		15.830
	PURCHASED ENERGY KWH MIX, %		
62	HEP		59.18
63	PGV	On Peak	15.45
64	PGV	Off Peak	10.39
65	PGV - Addt'l	On Peak	3.09
66	PGV - Addt'l	Off Peak	2.36
67	Wailuku Hydro	On Peak	2.26
68	Wailuku Hydro	Off Peak	1.62
69	Hawi Renewable Dev.	On Peak	3.33
70	Hawi Renewable Dev.	Off Peak	1.50
71	Apollo (Kamaoa)	On Peak	0.48
72	Apollo (Kamaoa)	Off Peak	0.20
73	Other (>100 KW)	On Peak	0.07
74	Other (>100 KW)	Off Peak	0.05
75	Other (<100 KW)		0.02
			100.00
76	COMPOSITE COST OF PURCHASED ENERGY, ¢/kWh		13.631
77	% Input to System kWh Mix		56.68
78	WEIGHTED COMP. PURCH. ENERGY COST, ¢/kWh (lines (76x77))		7.72605
79	BASE PURCHASED ENERGY COMPOSITE COST, ¢/kWh		13.631
80	Base % Input to Sys kWh Mix		56.68
81	WEIGHTED BASE PURCH ENERGY COST, ¢/kWh (lines (79 x 80))		7.72605
82	COST LESS BASE(lines (78 - 81))		0.00000
83	Loss Factor		1.090
84	Revenue Tax Req Multiplier		1.0975
85	PURCHSD ENERGY FCTR, ¢/kWh (lines (82 x 83 x 84))		0.00000

Line	SYSTEM COMPOSITE	
86	GEN AND PURCHASED ENERGY FACTOR, ¢/kWh (lines (47 + 85))	0.00000
87	Not Used	0.000
88	Not Used	0.000
89	ECA Reconciliation Adjustment	0.000
90	ECA FACTOR, ¢/kWh (lines (86 + 87+ 88 + 89))	0.000

Reference: HELCO-RWP-2204

Hawaii Electric Light Company, Inc.

Comparison of Rebuttal Testimony versus Direct Testimony Sales Heat Rate
(btu/kwh sales)

	Rebuttal Testimony [1]	Direct Testimony	Difference
Central Station with Wind/Hydro	14,826	14,874	-48
Steam	15,615	15,640	-25
Diesel	13,526	13,627	-101
Wind/Hydro	14,826	14,874	-48

1 HELCO-R-406, lines 17 through 20.

Hawaii Electric Light Company, Inc.

Comparison of 2006 Test Year
Energy Cost Adjustment Factor at Present Rates
(¢/kwh)

CA [1]	HELCO Rebuttal	Difference
8.621	8.998	-0.377

[1] CA-210, line 75.

Hawaii Electric Light Company, Inc.

Comparison of 2006 Test Year
Sales Heat Rate
(btu/kwh sales)

	CA [1]	HELCO Rebuttal [2]	Difference
Central Station with Wind/Hydro	14,872	14,826	46
Steam	15,631	15,615	16
Diesel	13,089	13,526	-437
Wind/Hydro	14,803	14,826	-23

1 CA-206, lines 17 through 20.
2 HELCO-R-406, lines 17 through 20.

Witness HELCO T-23

has no rebuttal testimony.

Witness HELCO T-23

has no rebuttal exhibits.

Witness HELCO T-24

has no rebuttal testimony.

Witness HELCO T-24

has no rebuttal exhibits.